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ENERGY



Advanced Distribution Management System (ADMS) Program

Multi-year Program Plan 2016 – 2020

Office of Electricity Delivery and Energy Reliability
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Executive Summary (DOE)

The Advanced Distribution Management System (ADMS) Program was established in FY 2016 within the U.S. Department of Energy (DOE) Office of Electricity Delivery and Energy Reliability (OE) Smart Grid R&D Program. The mission of this new Program is to develop a software platform capable of integrating current and emerging distribution utility data, including real-time, spatial data of all connected devices, and to support development of vendor independent measurement and control applications to manage and optimize distribution utility operations for improved reliability, resiliency, efficiency, asset protection, and integration of distributed energy resources (DERs).

Traditional distribution management systems (DMSs) face key technical challenges in managing and optimizing a modernized grid. These challenges include managing the complexity of operating the distribution systems with increasing levels of variability in both generation and load assets; implementing a holistic approach to coordinate and manage grid operations from transmission, to distribution, and to local energy networks such as microgrids and buildings; utilizing real-time, spatial data of all connected devices in determining the grid state for improved operational planning, protection, control, and optimization; and achieving interoperable and integrated operations between legacy and new and emerging systems and applications.

The ADMS Program is designed to overcome these challenges with the following vision:

By 2030, electric distribution grid management systems will be transformed from proprietary, vendor specific products to systems based on an open architecture and standards-based data exchange that will enable integrating and managing all assets and functions across the utility enterprise regardless of vendor or technology. Through this transformation, DMS vendors will adopt the DOE open, standards-based framework approach in the development of future ADMS product offerings and applications for utility customers.

The ADMS Program activities are organized into the following five technical areas:

- **ADMS Development Platform.** Develop an open-source ADMS application development platform to facilitate development of ADMS applications, integrate such applications into operational systems, provide a testing and evaluation framework to quantify benefits of ADMS applications, and provide an extensible development environment that is open-source and accessible to all industry stakeholders.
- **ADMS Testbed.** Build a comprehensive ADMS testbed to test ADMS functionalities from multiple vendors that span multiple utility management and data collection systems. This testbed will be used for testing of ADMS solutions with multiple legacy and advanced systems and for testing of use cases to enable utilities to evaluate the full benefits of ADMS applications.
- **ADMS Applications.** Develop a suite of ADMS applications, based on the ADMS platform, that: facilitate integration of high levels of distributed renewables, improve operational visibility, increase reliability and resiliency, reduce infrastructure upgrade costs, facilitate transmission support services, enhance power quality, enable microgrid coordination, and reduce energy costs, all while maintaining personnel and customer safety.

- **ADMS Foundational: Advanced Control.** Develop control theory and system architecture to create concrete directions of theoretical development consistent with defined metrics; develop theory to enable the design and analysis of control algorithms for at least 10,000 DERs embedded in distribution and transmission networks; and conduct at-scale testing by simulation to validate the performance of the developed control solutions and foster development of transition plans for industry demonstrations.
- **ADMS Integration with Energy Management System (EMS) and Building Energy Management System (BMS).** Develop an open framework to coordinate EMS/DMS/BMS operations; and deploy and demonstrate the coordinated operations in transforming or extending existing EMS and DMS applications. This area will also investigate methods and develop software tools that utilize data from sensor networks at different spatial and temporal scales to: forecast and monitor grid health, detect incipient failures or faults and locate their source, manage the response to a grid event, and develop strategies for mitigating future events.

The outcomes and benefits of the ADMS Program, through investing in the five technical areas, are reflected in the SMART (specific, measurable, agreed upon, realistic, and timely) goal targets that have been defined by the Program. Namely, by 2030, the developed ADMS solutions will achieve interoperable operations of all prevailing distribution utility applications, while meeting the following specific targets as compared to the baseline of utility operations without a DMS:

- 40% reduction in DMS deployment costs and time
- 80% reduction in outage time of critical and non-critical load
- 40% increase in system efficiency
- Support operations with 100% DER

Interim performance targets in 2020 and 2025 have also been set by the Program to progressively advance toward the 2030 targets. Further, the Program will promote adoption of open architecture, standards-based ADMS solutions by all DMS vendors, targeting 20%, 50%, and 100% of vendors having ADMS capabilities in 2020, 2025, and 2030, respectively.

The ADMS Program will closely coordinate with the DOE Grid Modernization Initiative activities undertaken by the Grid Modernization Laboratory Consortium and its partners, the DOE Advanced Research Projects Agency-Energy programs, other OE programs, and the DOE Office of Energy Efficiency & Renewable Energy programs. Effective industry engagement will be key to the success of the ADMS Program. The Program has devised industry engagement strategies at the Program level and for each individual technical area.

This Multi-Year Program Plan (MYPP) further describes specific activities and/or tasks in each of the five technical areas for each year from FY 2016 through 2020. It is anticipated that this MYPP will be updated annually to reflect current state of advances, priority needs, and resources availability.

1. Introduction

1.1. U.S. Department of Energy (DOE) Definition of ADMS

The DOE defines an advanced distribution management system (ADMS) as a software platform capable of integrating current and emerging distribution utility data, measurement, and control applications from varying vendors, and utilizing real-time, spatial data of all connected devices, to manage and optimize distribution utility operations for improved reliability, resiliency, efficiency, asset protection, and integration of distributed energy resources (DERs)¹.

An ADMS differs from a traditional distribution management system (DMS) in that it integrates operations across the numerous systems and applications that are typically isolated or, at best, loosely coupled. These systems and applications include, but are not limited to: Energy Management Systems (EMS), Distributed Energy Resource Management System (DERMS), Supervisory Control and Data Acquisition (SCADA), Outage Management Systems (OMS), Graphical Information Management Systems (GIS), Advanced Metering Infrastructure (AMI) and Meter Data Management Systems (MDMS), Customer Information Systems (CIS), Fault Location Isolation and Service Restoration (FLISR), mobile workforce tools, feeder load balancing and optimization, voltage optimization control, and distribution state estimation. By integrating operations across all of these systems and applications, ADMS technologies provide utilities with greater ability to observe and control distribution systems so as to address rising operational complexities while ensuring reliable and resilient operations.

1.2. Vision

The vision of the DOE ADMS Program is:

By 2030, electric distribution grid management systems will be transformed from proprietary, vendor specific products to systems based on an open architecture and standards-based data exchange that will enable integrating and managing all assets and functions across the utility enterprise regardless of vendor or technology. Through this transformation, DMS vendors will adopt the DOE open, standards-based framework approach in the development of future ADMS product offerings and applications for utility customers.

Adoption of ADMS by industry will be facilitated by having the Program activities respond to the four drivers for ADMS investments² described as follows with the abilities underlying the drivers proven through field demonstrations.

1. **Resilience:** the ability to withstand or recover from a natural disaster quickly.

¹ The term DERs is used herein to include cleaner and renewable distributed generation systems (solar PV, wind, combustion engines, combined heat and power, microturbines, micro hydro power, and fuel cells), electric vehicles, responsive building loads, energy storage, and demand response.

² The four drivers for ADMS investments are documented in the DOE report, “Voices of experience: Insights into advanced distribution management systems,” February 2015 (<http://energy.gov/sites/prod/files/2015/02/f19/Voices%20of%20Experience%20-%20Advanced%20Distribution%20Management%20Systems%20February%202015.pdf>).

2. **Renewables:** the ability to accommodate larger quantities of distributed energy resources.
3. **Replacement:** the ability to supplement legacy systems that are unable to integrate with new technologies and that staff can no longer support.
4. **Regulation:** the ability to accommodate changes that encourage reliability and efficiency.

1.3. Challenges and Opportunities

Managing and optimizing a modernized grid presents new challenges for traditional DMS solutions. Key technical challenges, which also pose as opportunities for the ADMS to address and overcome, are identified below:

- **Accommodating growing deployment of DERs.** The increasing penetration of DERs introduces higher levels of variability in both generation and loads, prompting a shift in load following from a central power station operational model to a distributed supply model to effectively balance electricity supply and demand in real time. These changes are increasing the complexity of operating distribution systems that deliver power to electricity end users. Distribution utilities face additional challenges in coordinating new DERs that may be owned by the utility, third-parties, or utility customers.

The increasing penetration of renewable generation in many electrical transmission and distribution grids is decreasing the availability of traditional forms of generation used to control real power for balancing load and reactive power for regulating voltage magnitude. ADMS has the opportunity to leverage a large latent capability in the grid by controlling DERs to supplement and replace the control provided by traditional generation, while allowing the grid to operate with leaner reserve margins.

- **Enabling an integrated system approach to electric power system operations and control that spans transmission, distribution, and local energy networks such as buildings and microgrids.** The current approach to electric power system operations and controls was developed over the last three to four decades in a piecemeal fashion, within narrow functional silos for DMS and EMS software tools that offer minimal ability to coordinate or interact. Additionally, end-use tools such as Building Energy Management Systems (BMSs), DERMS, and microgrid operations and control tools are typically independent from grid control software systems. This approach does not match the reality of complex smart grid systems, where renewables and electric energy storage in the distribution network and changing end-user consumption patterns have significant impact throughout the entire network. Additionally, utilities need the flexibility to choose the vendor solution that best fits their needs, and not be overly constrained by cross platform integration cost issues.

Future grid operations and control systems must be able to monitor, protect, and autonomously optimize the operation of the grid's interconnected elements—from the central and distributed generators through the high-voltage network and medium- and low-voltage distribution systems, to building automation systems, to controllers for DERs and microgrids, and to end-use consumers including their thermostats, electric vehicles, appliances, and other household devices. These provide opportunities for ADMS to apply interoperability and integration capabilities and to develop next-generation applications

for an integrated system approach. The integrated system approach will also help to “future proof” these systems in the event that the industry evolves in unexpected ways.

- **Utilizing real-time, spatial data of all connected devices to manage and optimize grid operations.** National grid modernization efforts to facilitate adoption of smart grid practices in recent years have increased adoption of measurement technologies, such as phasor measurement units (PMUs), smart meters, line sensors, and health condition monitors. This large influx of data offers increased capabilities to determine the behavior of the electric system in real time; however, without the proper infrastructure and analytics capabilities, it can overwhelm data acquisition, data storage, and data analysis systems.

The opportunity areas for ADMS applications development include big data management, integration of disparate data types, and advanced analytics. The developed ADMS applications will provide open-source tools capable of handling multi-source and multi-scale data from disparate sources to manage and optimize grid operations in an environment with potentially high penetration of DERs.

- **Achieving interoperable and integrated operations between legacy and new and emerging systems.** Currently, DMS and some ADMS capabilities are provided in vendor specific products. One of the single largest challenges that utilities face when operating a DMS or an ADMS system is the interconnections and interoperability with peripheral systems such as GIS, OMS, CIS, AMI, and SCADA, especially when multiple vendors are involved. The high cost and lengthy time for individual utilities to invest in custom solutions for integrating varying vendor products, including the data historian, can be prohibitive, particularly for small and medium size utilities.

ADMS applications within the individual electric power system vendor tool suites are emerging. Given the early nature of ADMS development, the timing is opportune for DOE to introduce open architecture, standards-based solutions to vendors for acceptance in their development approaches of ADMS for product offerings to utility customers.

- **Accommodating new architectural and operational constructs for distribution networks.** Currently, new distribution system architectures and operational management are being developed for distribution networks. These are being put forth in the distribution system platform provider (DSPP) model as part of New York’s *Reforming the Energy Vision activity*, and in the distribution system operator (DSO) model in California. Further work along these lines will occur to support increased levels of renewable resource penetration in distribution networks.³ This work may naturally lead to distribution system operational models that require new classes of ADMS applications supporting the new architectures and associated functionality.

³ De Martini, Paul, and Lorenzo Kristov, “Distribution Systems in a High Distributed Energy Resources Future,” Future Electric Utility Regulation Report No. 2, Oct. 2015, Lawrence Berkeley National Laboratory (https://emp.lbl.gov/sites/all/files/FEUR_2%20distribution%20systems%2020151023_1.pdf).

1.4. MYPP Technical Areas

The DOE ADMS Program was established to develop an open ADMS platform, develop new ADMS applications, validate performance capabilities, and transfer the open, standards-based ADMS solutions to industry for adoption. The performance capabilities developed through the DOE program will be validated both for interoperable operations among integrated applications and for improved utility operations. The applications will include the current, full suite of distribution utility applications (distribution automation, outage management, meter data management, and enterprise management), as well as new applications (high penetration of DERs; integration of transmission, distribution, and building energy management systems; integration of multiple microgrids; integration with other critical infrastructural systems). The improved utility operations will be validated against the following performance metrics: reliability; deployment costs; reduction in failed components; reduction in restoration time; reduction in system losses; system efficiency; and percentage DER integrated with the grid.

Key technical areas of the DOE ADMS Program include:

- **ADMS Development Platform.** Develop an open-source ADMS application development platform to facilitate development of ADMS applications, integrate such applications into operational systems, provide a testing and evaluation framework to quantify benefits of ADMS applications, and provide an extensible development environment that is open-source and accessible to all industry stakeholders.
- **ADMS Testbed.** Build a comprehensive ADMS testbed to test ADMS functionalities from multiple vendors that span multiple utility management and data collection systems. This testbed will be used for testing of ADMS solutions with multiple legacy and advanced systems and for testing of use cases to enable utilities to evaluate the full benefits of ADMS applications.
- **ADMS Applications.** Develop a suite of ADMS applications, based on the ADMS platform, that: facilitate integration of high levels of distributed renewables, improve operational visibility, increase reliability and resiliency, reduce infrastructure upgrade costs, facilitate transmission support services, enhance power quality, enable microgrid coordination, and reduce energy costs, all while maintaining personnel and customer safety.
- **ADMS Foundational: Advanced Control.** Develop control theory and system architecture to create concrete directions of theoretical development against defined metrics; develop theory for hierarchical, decentralized, distributed, and risk-aware controls to enable the design and analysis of control algorithms for at least 10,000 DERs embedded in distribution and transmission networks; and conduct at-scale testing by simulation to validate performance of the developed control solutions and foster development of transition plans for industry demonstrations.
- **ADMS Integration with EMS and BMS.** Develop an open framework to coordinate EMS/DMS/BMS operations; and deploy and demonstrate the coordinated operations in transforming or extending existing EMS and DMS applications. This area will also investigate methods and develop software tools that utilize data from sensor networks at different spatial and temporal scales to: forecast and monitor grid health, detect incipient failures or faults and locate their source, manage the response to a grid event, and develop strategies for mitigating future events.

1.5. Program Coordination

The ADMS Program supports and contributes to the DOE's Grid Modernization Initiative (GMI) to enable a modernized grid. The GMI research, development, and demonstration (RD&D) agenda is described in the DOE Grid Modernization Multi-Year Program Plan (MYPP).⁴ As such, the program activities will closely coordinate with those among the more than 80 projects awarded in 2016 to the Grid Modernization Laboratory Consortium (GMLC) to address the priorities identified in the Grid Modernization MYPP. This coordination with GMLC projects will involve the 14 DOE National Laboratories serving as the core for the GMLC, as well as their partners, including dozens of industry, academia, and state and local government agencies across the country. Examples of some specific GMLC projects for coordination by the ADMS program are listed below:

| | |
|-------------|---|
| GMLC 1.1: | Foundational Analysis for Grid Modernization Initiative (for system control metrics) |
| GMLC 1.2.1: | Grid Architecture |
| GMLC 1.2.2: | Interoperability |
| GMLC 1.2.3: | GMLC Testing Network |
| GMLC 1.2.5 | Grid Sensing and Measurement Strategy |
| GMLC 1.4.1 | Standards and Test Procedures for Interconnection and Interoperability |
| GMLC 1.4.2 | Definitions, Standards, and Test Procedures for Grid Services |
| GMLC 1.4.15 | Development of Integrated Transmission, Distribution, and Communication Models |

The ADMS Program will also coordinate with related, advanced energy technology R&D efforts funded by the DOE Advanced Research Projects Agency-Energy (ARPA-E) programs. For example, ADMS control and integration will leverage work being performed by ARPA-E's Network Optimized Distributed Energy Systems (NODES) program that is developing innovative hardware and software solutions to integrate and coordinate generation, transmission, and end-use energy systems at various points on the electric grid. In addition, new power system network models and new grid optimization algorithms developed through the ARPA-E's Generating Realistic Information for the Development of Distribution and Transmission Algorithms (GRID DATA) program will be closely monitored for ADMS applications.

Existing partnerships with utilities, manufacturers, private-sector research institutions, and state and local government agencies will be leveraged for coordination on ADMS planning, development, and implementation. These partnerships include those established under GMLC projects, through the DOE user facilities (such as the Electricity Infrastructure Operations Center [EIOC] at Pacific Northwest National Laboratory [PNNL] and the Energy Systems Integration Facility [ESIF] at National Renewable Energy Laboratory [NREL]), and through other existing DOE programs at the Offices of Electricity Delivery & Energy Reliability (OE) and Energy Efficiency & Renewable Energy (EERE). Further, the ADMS Program has assembled a Steering Committee consisting of nine members from industry⁵ to guide the Program and its projects to further strengthen the work with industry throughout all stages of ADMS RD&D.

⁴ Department of Energy, "Grid Modernization Multi-Year Program Plan," April 2015 (<http://energy.gov/sites/prod/files/2016/01/f28/Grid%20Modernization%20Multi-Year%20Program%20Plan.pdf>).

⁵ The ADMS Program Steering Committee comprises thought leaders and experts from industry in fields pertinent to ADMS development and applications. Current Committee members are from the following companies: ABB, Inc.; CenterPoint Energy; Cisco; Duke Energy; GE; GSD Energy Consultants; IBM; Milsoft; and Schneider Electric.

1.6. Program Goals and Multi-Year Targets

By 2030, the developed ADMS will achieve interoperable operations of all prevailing distribution utility applications, while meeting the following specific targets as compared to the baseline of utility operations without a DMS:

- 40% reduction in DMS deployment costs and time
- 80% reduction in outage time of critical and non-critical load
- 40% increase in system efficiency
- Support operations with 100% DER

Interim performance targets in 2020 and 2025 have also been set by the Program to progressively advance toward the 2030 targets. Further, the Program will promote adoption of open architecture, standards-based ADMS solutions by all DMS vendors, targeting 20%, 50%, and 100% of vendors having ADMS capabilities in 2020, 2025, and 2030, respectively.

2. Program Benefits

ADMS aims to reduce restoration and recovery times for outages under normal conditions and under all-hazards events. This leads to a reduction in the economic costs of power outages. The ability of ADMS to operate distribution level assets—owned by utilities, customers, and third parties—in a more flexible manner will reduce the need for overly conservative reserve margins, directly reducing their costs and improving system efficiencies. Further, ADMS will provide the increased observability and controllability of electric distribution systems, resulting in reducing the uncertainty associated with DERs. The increased observability and controllability will also allow distribution utilities to adopt technologies to better control their grid for higher reliability, improved power quality, security of people and data, and resiliency to natural disasters and other threats. Together, these result in a more reliable, lower cost power system, which, in turn, provides long-lasting U.S. economic impact.

Hence, through the new capabilities and applications enabled by the ADMS Program efforts, the Program will deliver benefits to utility planning and operations in advancing each of the following performance metrics:

- cost reduction;
- reliability enhancement;
- resilience enhancement;
- system efficiency improvement; and
- high DER penetration.

The quantitative benefits targeted for delivery by the DOE ADMS Program are manifested in the Program's 2030 goal targets and interim targets in 2020 and 2025 (See Section 1.6).

3. Technical Areas

The ADMS Program R&D activities are structured into the five technical areas summarized in the previous section. Each of these technical areas is described in further detail below.

3.1. ADMS Development Platform

3.1.1. Technical goal and objective

The goal of the ADMS development platform is to enable cost-effective and timely development, integration, and deployment of new ADMS applications that take advantage of the increasing amount of data made available through utility deployments of smart grid devices and systems. Key to this goal is developing a vendor agnostic interconnection layer so that various DMS systems, their peripheral systems, and other applications can be more effectively interconnected. As described in the DOE document “Voices of Experience,”⁶ utilities would like to reduce integration costs and have access to best-of-breed solutions from multiple vendors while avoiding stranding investments in legacy systems.

3.1.2. Technical challenge

ADMS deployments integrate data and information from a variety of systems. Depending on the size of the utility and prior investments in systems to support distribution system operations, the deployment and integration task grows in complexity. Key technical challenges include:

- Enabling deployment of multi-vendor ADMS applications.
- Establishing an ADMS application development methodology and environment that is not vendor dependent but that can be the source of ADMS applications usable in multiple vendor systems.
- Demonstrating benefits of ADMS applications.
- Providing means of integration of ADMS applications with existing data and systems, including, but not limited to: EMS, DERMS, SCADA, OMS, GIS, AMI and MDMS, CIS, and FLISR.

3.1.3. Technical scope

To accelerate the deployment of ADMS technologies this technical area will focus on building an open-source ADMS application development platform to facilitate development of ADMS applications and overcome the barriers to ADMS deployment. The open-source platform will be called OSPRREYS (Open Source Platform for Reliable and Resilient Electricity Systems).

The OSPRREYS platform will facilitate ADMS application development and integration of such applications into operational systems; provide a testing and evaluation framework to quantify benefits of ADMS applications; and provide an extensible development environment that is open-source and accessible to all industry stakeholders. Additionally, the OSPRREYS platform will be replicable at national laboratories, universities, and vendor facilities to ensure that the developed capabilities benefit the largest possible number of industry stakeholders.

3.1.4 Status of current development

Currently ADMS capabilities are provided in vendor-specific products. There is some movement by the vendors to apply current industry standards such as the Common Information Model (CIM), but this is not being performed uniformly.

ADMS applications within the vendor tool suites are emerging, and independent applications outside the vendor tool suites are also gaining momentum. Given the early nature of ADMS, there

⁶ Ditto, Ref. 2.

is opportunity to influence the manner in which vendors approach providing these capabilities to customers.

The vendor community is also segmented in several ways that reflect both the size and history of the vendors as well as the size and nature of the target utility customers. Generally speaking, some of the larger utilities are beginning to consider vendor supplied tool suites that may include ADMS capabilities, while others are defining their own requirements for such systems with subsequent plans to build such an environment and tool suite themselves. Small and medium size utilities typically have a more limited set of operational tools that may not, for example, even include a DMS. A key challenge is to enable ADMS applications for the small- and medium-sized utilities.

3.1.5. Federal role

The federal government has the opportunity to act as a neutral third party developing and making available vendor agnostic technology that is useful to both the vendors and utilities. In addition, the federal government can help establish the benefits of ADMS applications and related technology to help vendors to focus their efforts on products that provide maximum benefit to customers. Through taking an open architecture, open-source, reference implementation approach, the federal government enables market competition and the creation of “best of breed” applications available to all utilities.

3.1.6. Technical activity descriptions

The technical activities for ADMS Platform development and deployment will be based on an incremental software development and release approach. Such an approach establishes an initial documentation of functional requirements that are translated into an architecture and system conceptual design. From that, the scope of the first release cycle is defined, followed by physical design and implementation of that scope of functionality. Each release cycle finishes with testing, release, and then review of the functional requirements, followed by conceptual design and then definition of scope for the next release.

Throughout the period of performance, this activity will engage with and receive guidance from an Industrial Advisory Board comprised of industry stakeholders from both utilities and vendors. The planned annual face-to-face meetings will be augmented by quarterly web meetings.

Year 1

The first year involves project startup activities including planning and formation of the Industry Advisory Board along with tasks supporting the design and first development cycle for the ADMS Platform.

Two key tasks are (1) documentation of the ADMS Platform conceptual design and (2) functional requirements specification. The conceptual design will include a high level architecture, an initial version of which is shown in Figure 1, and a description of the general functionality and operation to be achieved in the ADMS Platform.

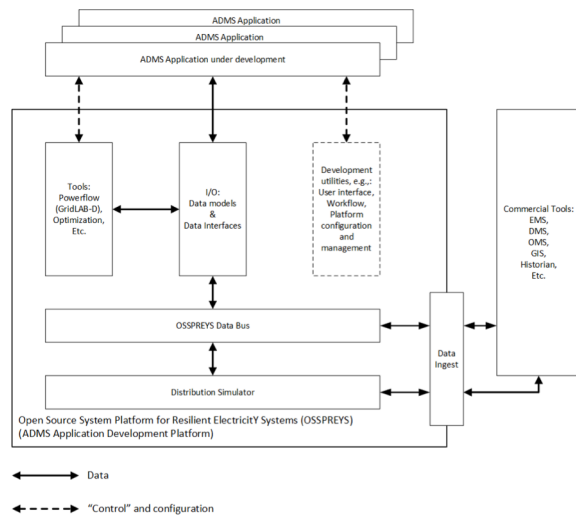


Figure 1. Open Source Platform for Resilient Electricity Systems (OSSPREYS)

The central feature of Figure 1 is the development platform that provides users with the ability to develop ADMS applications. The platform includes consideration for the various interfaces to data or other information; supporting functions such as power flow analysis, optimization calculations, and so forth; application user interface definition and mapping; access to a distribution utility simulation capability; and platform configuration tools. As shown in Figure 1, the platform provides interoperability through the standards-based data bus, data models, and data ingest or interface functions; and through the data bus and related components, interoperations take place with the distribution system

simulation tools and various commercial distribution system operation tools such as DMS, OMS, GIS, and EMS. In the development platform, an Input/Output function provides the data models and defined interface to the common data bus. Data will generally be accessed via the data bus. The available data may come directly from the distribution simulator (clean data) or from the distribution simulator via the commercial tools (more realistic, noisy data).

Major Task Elements for year 1 include:

- **Industrial Advisory Board (IAB).** The IAB will be formed during the first quarter of year 1. A face-to-face workshop with the board is planned near the end of the first quarter or beginning of the second quarter. Subsequently, quarterly web meetings will be held with the board.
- **ADMS gap analysis.** DMS has existed in various forms for well over a decade but they generally take the form of a collection of loosely integrated systems. Before the ADMS Program can determine the best course forward it will be necessary to map out the status of the current generation of DMS technology. This will include not only core DMS systems, but also peripheral systems that tie into DMS (for example, GIS, OMS, CIS, AMI, SCADA, etc.). This task will be completed in cooperation with the IAB to ensure an accurate representation of current state of the art, which will allow the program to focus on the gaps. The mapping of the current status of industry tools will be achieved through various means; these will include, but not be limited to, conversations with members of the IAB, conversations with utility stakeholders, review of vendor promotional material, review of trade publications, attendance at trade shows, and discussions with vendors.
- **ADMS platform conceptual design and functional requirements specification.** A conceptual design will be prepared documenting the technical approach and high-level system architecture for the ADMS platform. This will inform the functional requirements specification activity and will be updated based on the results of the functional requirements documentation. A key consideration in the conceptual design and the functional requirements definition will be identification and specification of interfaces between the ADMS platform and an application development environment and the

subsequent interfaces needed by ADMS applications in operational use. One of the single largest challenges that utilities face when operating an ADMS system is the interconnections and interoperability with peripheral systems such as DMS, GIS, OMS, CIS, AMI, and SCADA.

To address the challenges associated with multiple systems provided by different vendors, and the lack of transmission and distribution (T&D) integration, the ADMS platform will be an open-source platform, that is, OSPREYS, supporting ADMS interoperability. A general goal for OSPREYS development is to provide a vendor agnostic interconnection layer so that various DMS systems, their peripheral systems, and other applications can be more effectively interconnected. Work in this task will include participation in industry standards activities such as the CIM and IEC 61850. These challenges and design goals will be reflected in the functional requirements specification.

- **ADMS platform development operational environment configuration.** To support OSPREYS development and use, an operational environment that is representative of a distribution utility is needed. This environment will include commercial software systems that will interact with the ADMS platform.

The software systems of interest include traditional DMS as well as other common systems such as GIS, OMS, CIS, AMI, and SCADA. Where possible, more than one instance of each system will be included to ensure diversity of vendors. Approaching vendors about providing their software for the ADMS platform will also be a path to engage vendors as collaborative partners. In addition to the typical systems at the distribution level, EMS and BMS will be included because of their importance to future distribution system operations.

- **ADMS platform implementation.** From the complete set of functional requirements, a set representing core ADMS platform functionality will be identified for implementation in the first software development and release cycle. A development, testing, and release cycle of approximately six months is planned. An incremental approach allows for early results and manages the risk inherent in all such projects of having an incomplete set of requirements.

This implementation activity will include work to extend and adapt GridLAB-D⁷ with interfaces to the standards-based common data bus and for configuration via the sandbox configuration capabilities. The specific details of these modifications to GridLAB-D will be determined from the functional requirements specification.

Year 2

Year 2 will continue ADMS platform development with two more six-month development and release cycles planned. In addition, work will begin on specifying ADMS applications, evaluating the benefits of ADMS applications, extending to GridLAB-D, and developing a transition plan for moving the ADMS platform from the DOE efforts to broader use by utilities and vendors.

⁷ GridLAB-D™ is a power distribution system simulation and analysis tool developed by the DOE at PNNL. It is available for download (<http://www.gridlabd.org/>).

Year 3

A key task for year 3 will be a full first release of the ADMS platform. The ADMS platform will be deployed at NREL and Washington State University (WSU) for their use in developing at least one ADMS application each. In addition, an ADMS application will be developed at PNNL. Formal evaluation of the benefits of the ADMS applications will take place in year 3. Work on GridLAB-D to enhance its functionality in support of the ADMS platform will continue. Finally, implementation of the ADMS transition plan will begin.

Year 4

In year 4, the ADMS platform and/or example applications will be deployed at partner utilities. This will provide additional opportunity to evaluate the benefits of the applications developed and demonstrated in year 3 and for utilities to provide feedback on use of the platform to develop their own applications. At least one each of large, medium, and small utilities will be targeted for deployment.

Year 4 will also involve extensive interactions with the vendor community to define a path for full interoperability of OSPRREYS-based applications and functionality into product environments. Requirements will be defined for processes and technology to support realization of such an outcome. The long-term goal is the ability to have a means to certify that applications developed in an OSPRREYS-compliant ADMS application development tool will run in a similarly compliant vendor product.

Year 5

The expected activities in year 5 will be updates and improvements to the ADMS platform based on utility and vendor feedback from the year 4 deployments and tests, along with further steps toward the ability to have certified ADMS applications as described under year 4.

3.1.7. Milestones

Year 1

| Milestone Name / Description | End Date | Type |
|---|-----------------------|----------------------------|
| Milestone 1: Formalize the establishment of the IAB and schedule a date for the first annual in person meeting. | 3 months after start | Quarterly Progress Measure |
| Milestone 2: Complete mapping of the current industry state of the art for ADMS, including a complete gap analysis. | 6 months after start | Quarterly Progress Measure |
| Milestone 3: Complete specifications for the open-source ADMS platform. | 12 months after start | Quarterly Progress Measure |
| Milestone 4: Complete open-source release of OSPRREYS analytics engine. | 12 months after start | Quarterly Progress Measure |
| Annual SMART Milestone: Complete specifications for the open-source ADMS Platform. | 12 months after start | Annual Milestone |

Year 2

| Milestone Name / Description | End Date | Type |
|------------------------------|----------|------|
|------------------------------|----------|------|

| | | |
|---|-----------------------|----------------------------|
| Milestone 1: Complete initial development and construction of OSPRREYS in Richland, WA, including a release of the open-source code. This will coincide with an IAB workshop in Richland, WA. | 18 months after start | Quarterly Progress Measure |
| Milestone 2: Complete the specifications for the initial ADMS applications, including those to be developed at NREL and WSU. | 18 months after start | Quarterly Progress Measure |
| Milestone 3: Complete the QA plan for OSPRREYS and ADMS applications. | 18 months after start | Quarterly Progress Measure |
| Milestone 4: Complete the development of the transition plan. | 24 months after start | Quarterly Progress Measure |
| Milestone 5: Complete open-source release of OSPRREYS analytics engine. | 24 months after start | Quarterly Progress Measure |
| Annual SMART Milestone: Complete construction for initial phase of OSPRREYS in PNNL EIOC in Richland, WA. This will be held in conjunction with an in-person meeting of the IAB. | 24 months after start | Annual Milestone |

Year 3

| Milestone Name / Description | End Date | Type |
|--|-----------------------|----------------------------|
| Milestone 1: Deploy ADMS platforms at NREL and WSU. | 30 months after start | Quarterly Progress Measure |
| Milestone 2: Complete ADMS application development, testing, and evaluations at NREL and WSU. | 30 months after start | Quarterly Progress Measure |
| Milestone 3: Complete operator-based evaluations of ADMS applications in the EIOC. | 36 months after start | Quarterly Progress Measure |
| Milestone 4: Complete open-source release of OSPRREYS analytics engine. | 36 months after start | Quarterly Progress Measure |
| Annual SMART Milestone: Execute the transition plan for the project. This will include integrating results with two utilities, and releasing all developed open-source code. | 36 months after start | Annual Milestone |

Year 4

| Milestone Name / Description | End Date | Type |
|--|-----------------------|----------------------------|
| Milestone 1: ADMS application standardization workshop with key stakeholders | 42 months after start | Quarterly Progress Measure |
| Milestone 2: Deploy ADMS application at large utility. | 48 months after start | Quarterly Progress Measure |
| Milestone 3: Deploy ADMS application at small utility. | 48 months after start | Quarterly Progress Measure |

Year 5

| Milestone Name / Description | End Date | Type |
|--|-----------------------|----------------------------|
| Milestone 1: Complete requirements and plan for industry supported certified ADMS application development. | 54 months after start | Quarterly Progress Measure |
| Milestone 2: Update ADMS Platform open-source release based on feedback from vendor and utility users. | 60 months after start | Quarterly Progress Measure |

3.2. ADMS Testbed

3.2.1. Technical goal and objectives

This technical area will establish a vendor-neutral ADMS testbed to accelerate industry development and adoption of ADMS capabilities for the next decade and beyond. The testbed will enable utility partners, vendors, and researchers to evaluate existing and future ADMS use cases in a test setting that provides a realistic combination of multiple utility management systems and field equipment. The activity will work closely with an Industry Steering Group (ISG) to ensure that electric utility (“utility”) needs are met and use cases are realistic and valuable.

The ADMS testbed will allow utilities and vendors alike to evaluate: (1) the impact of ADMS functions on system operations; (2) interoperability among ADMS system components; (3) interactions with hardware devices; (4) integration challenges of ADMS with legacy systems; and (5) ADMS vulnerability and resiliency. The testbed will provide a less-expensive and lower-risk alternative to a pilot deployment, plus the ability to simulate contingency scenarios that are not practical to test using a real distribution system. The findings from ADMS testbed evaluations can improve effectiveness of subsequent trial deployments.

These ADMS testbed capabilities will speed industry adoption of ADMS systems, helping to meet the DOE Grid Modernization MYPP goals by: increasing grid reliability and resiliency by enabling the testing of ADMS responses to extreme events in a laboratory setting; reducing the economic impact of outages through faster, more automated distribution recovery; and driving down the costs of integrating DERs by incorporating DERs into system operations. This activity will support the Grid Modernization Major Technical Achievements by developing a testbed to evaluate ADMS contribution to (1) advanced modern grid planning on an analytics platform, (2) operating a distribution system reliably on lean reserve margins, and (3) controlling resilient distribution feeders with high percentages of low-carbon DERs (50%).

The activity will establish an integrated DMS/ADMS testbed within the GMLC Testing Network (GMLC-TN) that will allow utilities (including investor-owned utilities, municipalities, and cooperatives) and other stakeholders to evaluate technical, practical, and economic benefits/costs of ADMS features in a hands-on environment. This testbed will be vendor neutral, providing an open and modular framework to integrate software and hardware components from multiple vendors. To support these aims, the activity will also develop and validate test cases and scenarios based on specific ADMS functionality.

As Figure 2 shows, the testbed will support multiple test cases by: (1) *enhancing core DMS capabilities*—such as FLISR response, and Volt/VAR optimization (VVO) that includes coordinated conservation voltage reduction (CVR); and (2) *evaluating emerging ADMS capabilities*—such as controlling DERs along with regular distribution system operations, incorporating microgrids, distributed control schemes, and distribution automation.⁸ Furthermore, the testbed can facilitate interoperability testing of emerging and legacy utility operations systems from multiple vendors, and can simulate the control-room functions required to support forthcoming DER interconnection standards to support grid services.

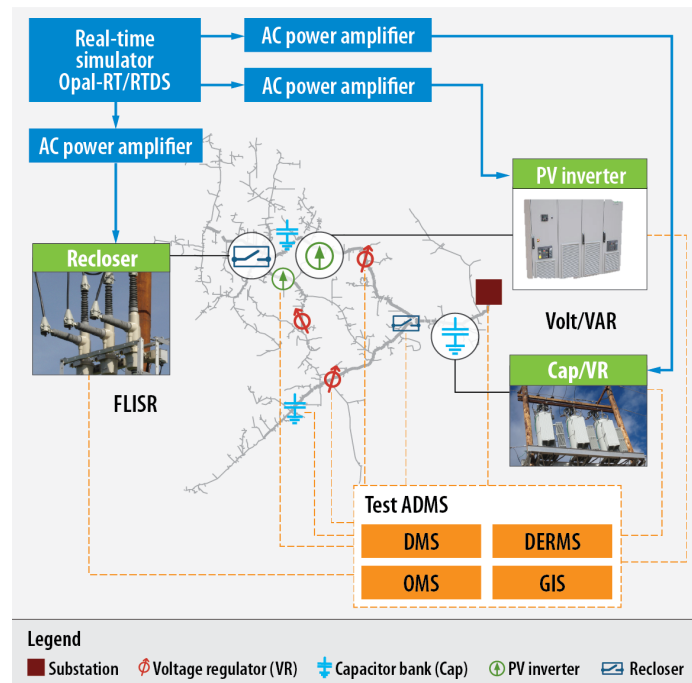


Figure 2. Conceptual diagram of the proposed ADMS testbed

3.2.2. Technical challenges

U.S. electric utilities are investing in grid modernization technologies such as ADMS to meet their customers' expectations of "higher reliability, improved power quality, renewable energy sources, security of their data, and resiliency to natural disasters and other threats that disrupt the flow of

⁸ R. Das, V. Madani, et al., "Distribution Automation Strategies: Evolution of Technologies and the Business Case," *IEEE Trans Smart Grid*, vol. 6, no. 4, pp. 2166-2175, 2015.

*power and their lifestyles.*⁹ The “advanced” elements of ADMS span multiple utility management systems and go beyond traditional DMS solutions by providing next-generation control capabilities. These capabilities include management of high penetrations of DERs, closed-loop interactions with BMSs, coordinated operation with microgrid controllers (MCs), and tighter integration with an increasingly diverse suite of utility tools for MDMS, OMS, asset data, billing, and more.

However, each utility electric distribution system is unique, thus making it difficult to predict the utility-specific technical and economic benefits of different ADMS functions such as FLISR, VVO, managing peak demand, and integrating BMSs, MCs, and DERMSs. It can be prohibitively expensive for individual utilities to invest in one-off or pilot deployments of an ADMS simply to understand the true benefits of the technology. Furthermore, it can be difficult or impossible to test the system response to faults and other extreme events that occur infrequently but where advanced functions can make a considerable difference. From a vendor perspective, emerging ADMS capabilities interact with an increasingly complex system of resources, making it difficult to develop and test new capabilities in isolation.

To overcome these challenges, this project will develop an ADMS testbed to provide utilities and vendors alike a neutral “sandbox” to try out, refine, and stress-test ADMS capabilities while interacting with realistic, but simulated, power systems that may also include actual hardware.

3.2.3. Technical scope

This activity will build a comprehensive ADMS testbed at the NREL’s ESIF to test ADMS functionalities from multiple vendors that span multiple utility management and data collection systems. This testbed will address the challenges faced by utilities in adopting ADMS technology by developing a realistic ADMS testbed—including megawatt-scale hardware testing and arbitrary system simulation—that will enable utilities to evaluate the full benefits of advanced functionality and test the integration of DMS systems with multiple legacy and advanced systems. This testbed and its use cases will leverage existing and new capabilities—some proposed through other Grid Modernization projects—at NREL and complementary locations at other national laboratories, including advanced large-scale grid simulation and extensive real-time hardware integration through power hardware in the loop (PHIL).

The ADMS testbed will house commercial DMS systems and complementary management systems from multiple vendors to enable utilities to work with known partners and potentially to use actual system data directly in the simulations. The ADMS under test will interface with a hybrid hardware/software simulation that represents the distribution network being controlled and also other systems with which the ADMS must interact, including transmission-level EMS and BMS. The core ADMS testbed will consist of a growing multi-vendor suite of off-the-shelf utility management systems, complete with simulated control room functions at the ESIF. This enterprise-class system will control a simulated distribution system through a combination of real-time software simulation coupled with PHIL. This approach allows users to accurately simulate the distribution system at both steady-state and dynamic timescales, and to assess performance and benefits of advanced ADMS functions. Later in the project, other real-time software models that represent the market and transmission systems will be modeled alongside the PHIL simulation, thus allowing testing of ADMS interoperability and system-level functions

⁹ Ditto, Ref. 2.

such as market participation of DERs and providing ancillary services. Finally, a system-level visualization will clearly portray the ADMS performance on timescales from sub-second to years, and from a single device to the entire utility region. This capability will greatly help in assessing the benefits of the use cases under test.

Figure 3 shows a functional block diagram of the proposed ADMS testbed. The ADMS under test consists of a DMS, SCADA interface, and other systems, which may include but not be limited to a DERMS, OMS, Demand Response Management System (DRMS), MDMS, MC, and BMS. It receives signals representing distribution system measurements through SCADA and through the ADMS to Simulator Link. These signals may either come from the DMS internal power-flow solver (existing, tested in Year 1) or from a multi-timescale software model of (most of) the distribution system (developed in Year 1, tested in Year 2). The multi-timescale model simulates the state of the network in real time based on the ADMS controls and produces virtual measurements of the system state.

Elements of the distribution system of particular interest that are difficult to model are represented by actual power hardware in NREL's ESIF labs. This may include, but not be limited to, distribution system equipment such as capacitor banks, protection equipment, and smart inverters. The power hardware actuates controls from the ADMS and interacts with the simulated part of the network via a real-time simulator (RTS) that controls the AC power amplifier voltages. Physical measurements from the power hardware, including voltages and currents, are fed back to the software simulation via the RTS to close the PHIL loop and also back to the DMS via SCADA to close the loop.

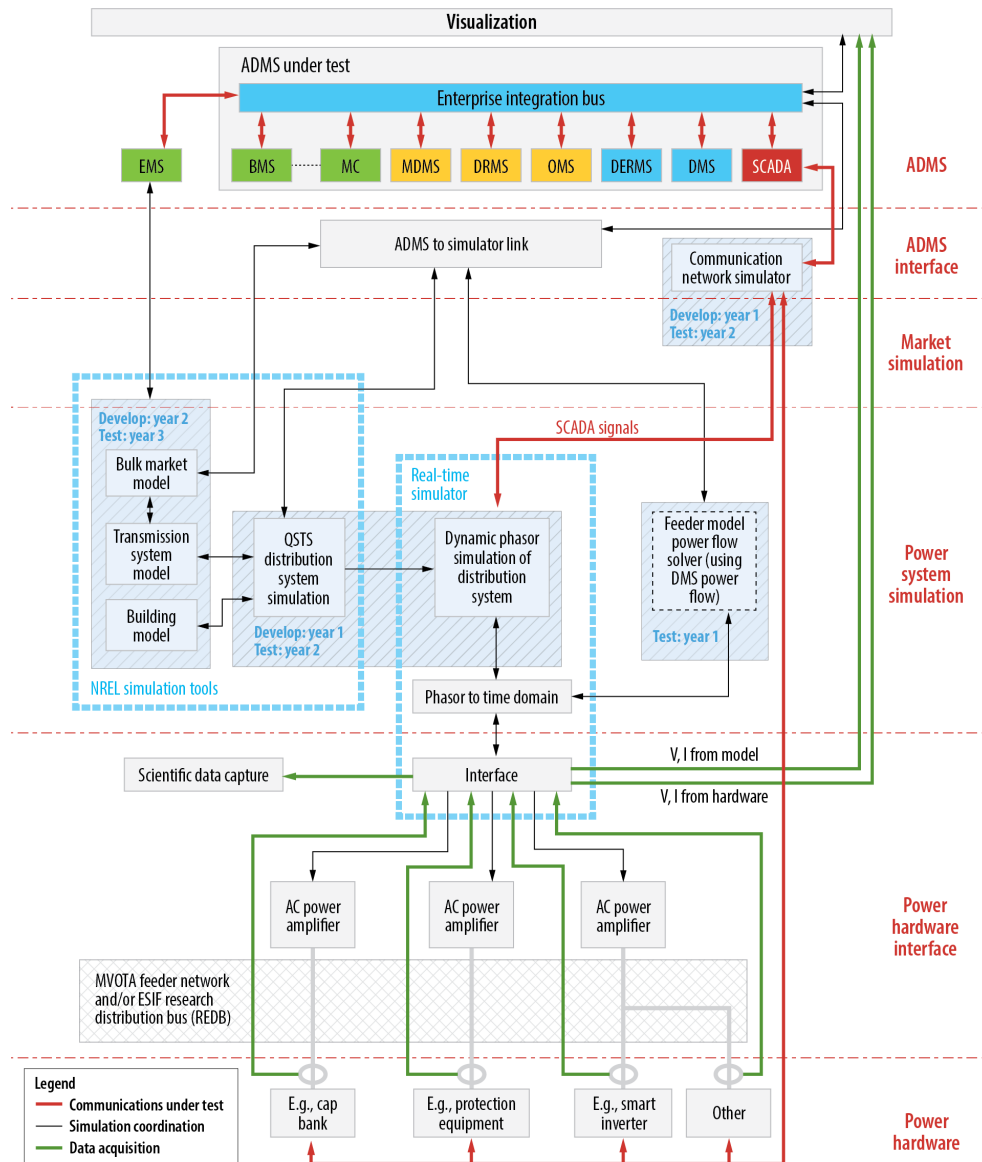


Figure 3. Proposed ADMS testbed functional block diagram

Figure 4 illustrates the PHIL architecture more explicitly. This approach allows the real-time simulation of complete distribution system models while representing parts of the network of particular interest in more detailed transient simulation or in hardware.

In addition to the PHIL simulation of the distribution system network itself, the ADMS testbed also includes a scientific data capture system, real-time modeling of buildings and BMSs, and an EMS that may be run at PNNL's EIOC and be connected remotely to the ADMS testbed at ESIF as one of the capabilities.

Interoperability between utility systems will be an important aspect of the testbed to maintain proper operation as new functionality is added to distribution system operations. The Electric Power Research Institute (EPRI) has recently developed web-based “test harnesses” to evaluate the conformance of DMS components to standardized messaging protocols that should simplify platform-level integration through the enterprise messaging bus. Under this activity, NREL will

work with EPRI to provide follow-on testing of interactions with the ADMS, its components, and connected distribution system hardware. This interoperability will ease the ability to swap and test multiple ADMS components from different vendors.

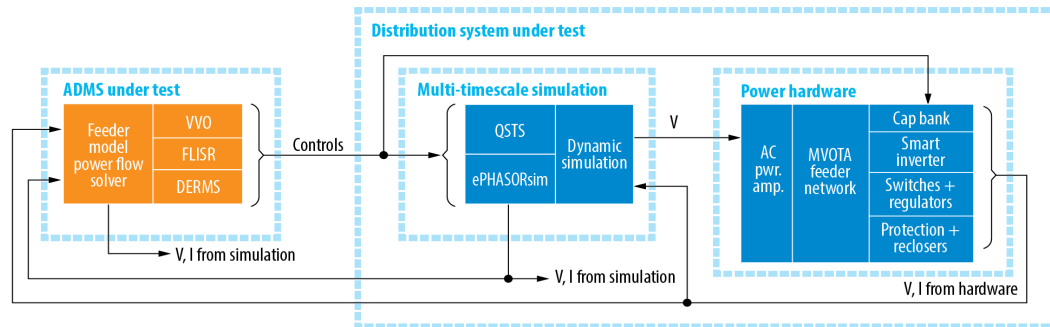


Figure 4: Detailed illustration of PHIL

3.2.4. Status of current development

NREL worked with Duke Energy and GE Grid Solutions to test a new VVO application that controls photovoltaic (PV) inverters as well as legacy capacitor bank and voltage regulator devices. This project involved building a limited prototype DMS testbed that linked the GE Grid Solutions DMS and training simulation environment to power hardware through PHIL testing. This setup was used and is being further developed to evaluate smart-inverter operations and DMS integration of a mock utility distribution feeder, and to compare the value of alternative Volt/VAR schemes to the utility. This project focused on the potential opportunities to use smart inverters to support voltage regulation for power distribution systems, and how to incorporate such capabilities in the software tools used by the utility to support grid operations. Manufacturers do not usually disclose the detailed control strategy for advanced inverters; therefore, the ESIF's ability to connect actual inverters to distribution system software models through PHIL testing is critical to this project. The capability developed in this project will serve as a foundation for the ADMS testbed development, and it will be further validated using a use case identified by the ISG in Year 1.

NREL is working with EPRI and Schneider Electric as part of the Integrated Network Testbed for Energy Grid Research and Technology Experimentation (INTEGRATE) program to advance intelligent control of connected devices. This work involves demonstrating an end-to-end framework of communication and control technologies, integrating operation of different domains within distribution systems (including DMSs, demand response services, and residential appliance scheduling) through open-source software tools. The framework includes an enterprise integration test environment, commercial ADMS from Schneider Electric, open-software platforms, open Home Energy Management System (HEMS) platform, communication modules, and applications. This project incorporates open standards in a mixed-standard environment, where multiple communication protocols will co-exist at ESIF—much as they might at an electric utility in the near future. Since this project will install Schneider Electric's ADMS at NREL, it provides a second system from which to evolve the integrated ADMS testbed.

As part of the DOE OE Smart Grid R&D Program, Argonne National Laboratory (ANL), EPRI, and NREL are working on the "Structuring DMS and MC Interaction" project. The objective is to develop integrated control and management systems for distribution systems with high

penetrations of interconnected generation from renewable energy sources (RES) as part of the grid modernization program. This project is closely related to the DMS studies completed in FY15 by ANL and EPRI.¹⁰ The “Structuring DMS and MC Interaction” project will lead directly to use cases related to integrating existing DMS platforms with ADMS, especially oriented toward DERMS and microgrids.

The PHIL, modeling, and simulation capabilities of ESIF are uniquely suited to being a testbed for these ADMS use cases and to support evolving requirements of partner utilities and vendors.

3.2.5. Federal role

Government and the national laboratories are uniquely suited to provide a neutral testbed to evaluate existing and future technologies on a common realistic utility framework. Doing so also leverages unique government facilities such as the ESIF to incorporate actual hardware devices at power. Through the testbed, utilities and other stakeholders will obtain a comprehensive, credible cost/benefit analysis of ADMS applications, which will greatly help utilities to plan ADMS implementation at significantly lower cost and without disrupting customers. Removing some of the uncertainty and barriers through independent testing at the testbed will help stimulate the market for ADMS and help utilities avoid the costly delays incurred today.

3.2.6. Technical activity descriptions

To achieve the goals set forth, the activity is divided into six major interacting tasks that span three years. Figure 5 shows the timing of the tasks, with additional detail provided below.

Task 1 involves managing the ADMS testbed ISG activities, including assembling an ADMS testbed ISG comprising utility power distribution personnel responsible for DMS/ADMS deployments and operations within their organizations. The ISG’s main objective is to identify and develop the use cases in collaboration with the project team. The ISG will also assist in developing the test plans.

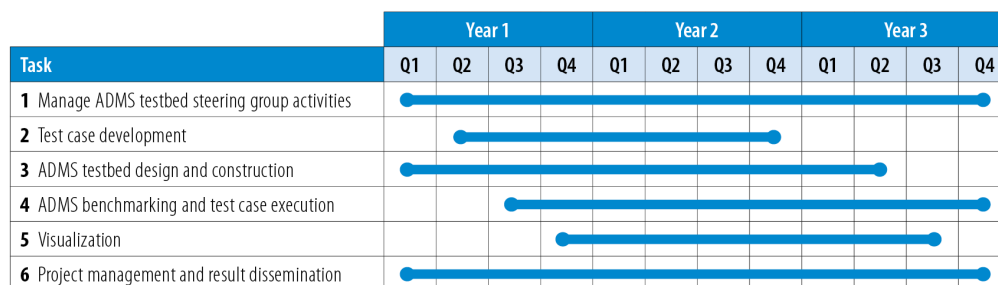


Figure 5. Timeline of the tasks

Task 2 is to identify the functionality and testing requirements of the ADMS testbed. In this task, spanning the first two years, use cases and test plans will be developed for Year 2 and Year 3, including testing of advanced functions that cover multiple utility systems. The use cases may include: (1) demonstration of integrated DMS, MC, and DERMS benefits at multiple timescales; NREL will work closely with ANL and EPRI on this use case; and (2) demonstration of integrated DMS, BMS, DRMS, and EMS benefits, in collaboration with PNNL (where EMS may be located at PNNL) and as illustrated in Figure 6.

¹⁰ Argonne National Laboratory, “Guidelines for implementing advanced distribution management systems: Requirements for DMS integration with DERMS and microgrids,” August 2015.

Task 3 will design and build the software and hardware infrastructure for the testbed. Circuits from partner utilities (distinct from ISG participants) will be partly simulated and partly emulated in the PHIL/controller hardware in the loop (CHIL) environment. The activity will involve working with the utilities and vendors to connect the proper hardware equipment in the ESIF Medium-Voltage Outdoor Test Area (MVOTA) and Power System Integration Lab (PSIL) to represent a selection of distribution equipment in a service territory. The work with the utility and ADMS vendor includes installing the ADMS and enabling communications with the hybrid hardware and software simulation. This task will occur mainly in the first two years. In Year 1, a multi-timescale distribution system simulation will be developed, consisting of a quasi-static time-series (QSTS) simulation for the distribution system and buildings, in conjunction with a phasor simulation (in Opal-RT's ePHASORsim) on the real-time simulator. NREL, EPRI, Opal-RT, and PNNL expertise in power-system modeling will be leveraged in this task. The multi-timescale distribution system simulation will be coupled with power hardware representing distribution system components of interest. In Year 2, the transmission power system model and bulk market model along with the BMS and EMS will be integrated to allow testing against static and dynamic system-scale phenomena. In addition to simulating ADMS operation in routine and anomalous conditions, this task will also test interoperability of ADMS components through a combination of one-at-a-time semantic test harnesses in partnership with EPRI, and full multi-component interoperability as part of larger tests. This task also accomplishes the core vulnerability testing needed for the system.

Task 4 includes baseline validation and benchmarking of the ADMS use cases identified by ISG, executing the test plans, and performing economic evaluations. To ensure that the testbed accurately models the utility feeders, a baseline of the testbed use cases on the modeled utility feeders will be performed by validating the base results against real-world data readily available from the utility. At least two ADMS use cases, developed jointly with the ISG in Task 2, will be tested using the testbed, and the results will be analyzed. Further, economic cost and benefit implications of the test cases to all the stakeholders will be developed using the data generated from the testbed.

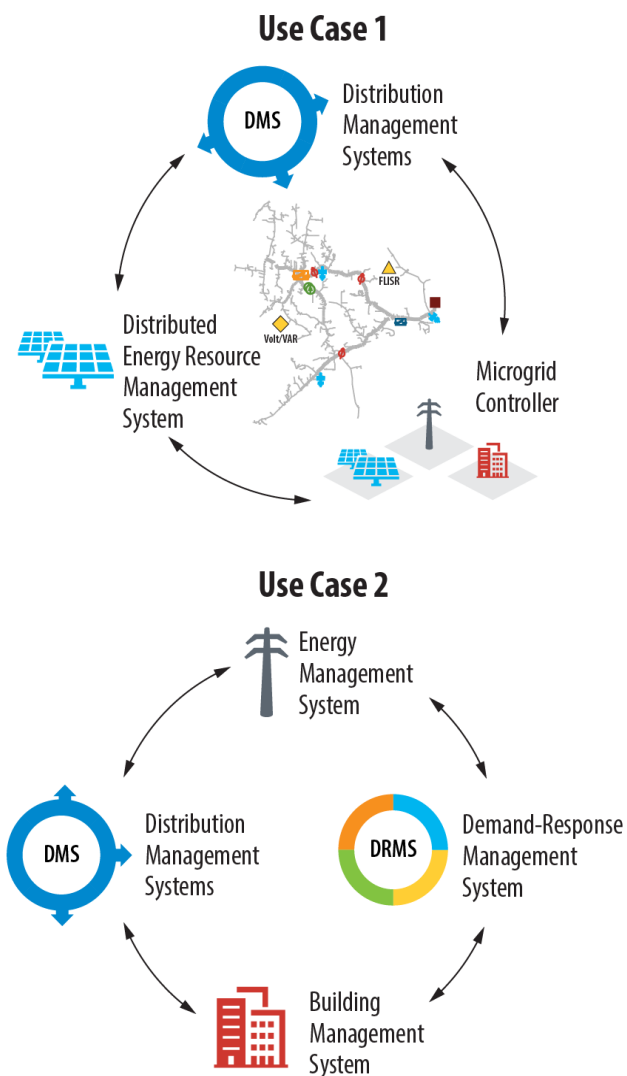


Figure 6. Depiction of example use cases

Task 5 is to develop the visualization capability. Multiple 2D and 3D visualization techniques will be developed to provide a human-machine interface (HMI) for the testbed. This capability will support the real-time monitoring of the testbed, as well as the in-depth analysis of the ADMS in post simulation. The visualization capability will provide the framework in which the benefits of the ADMS can be understood and illustrated.

Task 6 involves disseminating the results of tests to utility customers and conducting outreach to all the stakeholders. A two-day-long workshop will be conducted at appropriate locations to disseminate the final results. Specific studies conducted using the proposed ADMS tested will be documented and shared with the electric power industry through technical reports, fact sheets, journal articles, conference participation, and other communications.

3.2.7. Milestones

Year 1

Task 1 – Assemble ADMS testbed ISG

Task 2 – Test plan for Year 2

Task 3 – ADMS testbed multi-timescale software and hardware infrastructure development for Year 2 use case

Task 4 – Testbed for ADMS using intrinsic DMS power flow: Perform baseline validation and benchmarking for the chosen use case #0

Year 2

Task 2 – Develop test plan specifying tests to be conducted in Year 3

Task 4 – Complete execution of the Year 2 test plan

Task 6 – One-day workshop disseminating the lessons learned in ADMS use case #1

Year 3

Task 4 – Complete execution of the Year 3 test plan

Task 6 – One-day workshop disseminating the lessons learned in ADMS use case #2

3.3. ADMS Applications

3.3.1. Technical goal and objective

The overarching goal of this technical area is to develop an integrated suite of ADMS applications that: facilitate integration of high levels of distributed renewables, improve operational visibility and situational awareness, increase reliability and resiliency, reduce infrastructure upgrade costs, facilitate transmission support services, enhance power quality, enable microgrid coordination, and reduce energy costs, all while maintaining personnel and customer safety. Existing DMS applications provide a number of these services; however, these are rarely delivered in an integrated solution with cross-application coordination that uses applications in common for information such as state estimation and system identification. Applications are often vendor dependent and lack an interoperable interface.

3.3.2. Technical challenges

DMS applications are often constructed in a siloed manner, but they can and do interact.

- Transmission support functions and VVO could impact state variables in opposite directions (for example, if a transmission level request for added real power injection from storage coincides with high voltage magnitudes at the point of injection on distribution).
- Network flow impacts asset life; therefore, asset management and network optimization objectives overlap.
- DERMS can be configured for several different applications with related but not identical objectives, including applications that provide network optimization, applications that reduce infrastructure upgrade costs, or applications that maximize renewables hosting capacity.
- Demand response (DR) actions that reduce energy costs or avoid network capacity upgrade investments may degrade power quality and safety by creating phase imbalances, and involve CIS in addition to network controls.
- DR and DERMS can be used to perturb network flow conditions to facilitate parameter identification such as topology identification.

The challenge of developing interoperable ADMS applications is not only to avoid conflict, but to interact in synergistic ways that ultimately enable operators to coordinate network management and operation decisions. This requires platform development that facilitates application integration (as described in Section 3.1); it also requires developments that ensure that applications are not only compatible, but resolve conflicting objectives in ways that are transparent and customizable by operators. At a minimum, this will require information sharing and recognition of situations where application objectives either compete or complement each other. However, in some cases, the solution may be to collapse multiple applications into single subsuming applications. A major challenge will be to make complex application decisions and operator recommendations transparent and easily acted upon.

There are technical challenges to the problem of managing information across an ADMS. One of these is the challenge of developing software functions that leverage advanced sensor measurements to deliver real-time and forecasted information about system conditions. This information needs to be made available to relevant applications in a timely manner to ensure seamless operation; it must also be usefully interpreted and visible to operators. There is a need to develop tools to support sensor placement with many ADMS applications in mind. It will also be important to assemble and integrate state estimation algorithms that are both fast (for reliability and outage management purposes) and accurate (to ensure model-driven network decisions are as near to optimal as possible). Other supporting functions that are of use to many applications—including power flow analysis, load and DER forecasting, and optimization under uncertainty—must also be developed as common functions available to all DMS applications to ensure consistent decision-making and to avoid ambiguities.

Another challenge is that of managing applications with interacting objectives and control outputs. DER and electric vehicles (EVs) can and will put unprecedented strain on distribution and transmission system components. Potential impacts include phase imbalance, voltage excursions, and component overload. While these impacts can be managed with DERMS applications, DERs and EVs are also valuable to network optimization routines such as VVO and CVR. Synthesis of all of these constraints and objectives into a single decision making platform is desirable; however, there are significant challenges with respect to managing model fidelity, state estimation errors,

and forecast uncertainty as well as dealing with the computational cost of solving a problem that manages all of these issues simultaneously. Additionally, cybersecurity, communications, and interfaces for applications need to be standardized to facilitate secure, interoperable applications as well as data input and output.

Finally, significant challenges arise from the potentially uncertain availability of the DER for control, including increasing hosting capacity, avoiding network upgrade costs, and preserving power quality with “smart grid” strategies such as DER actuation or DR. For example, storage devices may reach state of charge capacity constraints, customers may opt out of DR programs, or solar PV output might be reduced by clouds or disconnected from customer rooftops. While these types of resources may be able to deliver network services for less expense than traditional measures (that involve, for example, conductor and capacity bank upgrades, capacitor bank installation, and voltage regulators), the uncertain nature of these emerging options relative to their traditional counterparts must be factored in to network optimization and planning decisions.

3.3.3 Technical scope

ADMS applications will be developed in three general domains: (1) Non-emergency network operations, (2) Reliability and outage management, and (3) Data analytics and visualization. The technical scope will focus on, at a minimum, integration of applications within each domain. These areas and how existing applications fit are described below. In describing these areas, the aim is to explore the scope of applications that can fall under the umbrella of an integrated ADMS and the generalities and interactions between applications.

Non-emergency network optimization. Applications in this domain will support or subsume traditional applications, including VVO, DERMS, DR, and transactive solutions for energy management. Emerging applications including transmission support services are also in this domain. Supporting functions include network model identification and power flow analysis.

Reliability and outage management. ADMS applications can avoid outages using available DER. In addition, they must also respond efficiently during unplanned outages, avoid service interruptions, and facilitate equipment repairs. A combination of applications assists in reliability by efficient communication of relevant fault locations in addition to advanced data analytics and operator performance visualization. DER can assist in management of outages by coordinating responses or providing microgrid support. Applications within this include,

- FLISR
- OMS & Workforce management
- Risk based analysis for failure
- Risk based analysis tools when considering high penetration of DER in the solution
- Predictive maintenance scheduling
- Reliability as a service in future

By developing appropriate analytics for operators and data integration, the best path for outage avoidance and management can be developed via a common user interface.

Data analytics and visualization. Key factors in data analytics and visualization include ensuring operators receive timely, useful information. Integration of forecasting and risk-based analysis with fast and accurate analysis and determination of the best choice for reconfiguration and control selection are key features for an ADMS. User interfaces and application integration are essential, along with appropriate sensor placement and planning. Traditionally, SCADA has been

considered the backbone of analysis, for management of peak and non-minimum load conditions, which often do not coincide with peak and minimum DER generation conditions. With development of data driven applications, and integration of customer metering to the interfaces, the selection of appropriate data for improved situational awareness will be essential. Supporting functions for data analytics and visualization include:

- state estimation and topology/parameter identification algorithms;
- load and distributed generation (DG) forecasting algorithms;
- switch plan management algorithms (discrete optimization); and
- analysis tools based on data provided from advanced sensors, including synchrophasors for power distribution systems, line sensors, smart meters, and fault indicators.

3.3.4. Status of current development

Current development within the ADMS application environment is fundamentally limited by a number of issues including application interoperability, data availability, communications infrastructure, and institutional issues.

- There are significant ADMS offerings from a number of the prevalent vendors, including ABB, GE (PowerOn), Schneider, and Siemens (Spectrum), with applications including DMS, SCADA, OMS, and EMS solutions.
- State-of-the-art analytics integration is being developed on parallel paths, with minimal effort to integrate into other ADMS applications.
- Communications backbones are generally limited to SCADA and (separately) smart meter status; it is usually difficult to access or integrate full information from low-voltage networks.
- GIS updates tend to be disconnected from the operations environment; planning and operations are rarely integrated.
- Smart meters location and phasing is often unknown, thus suggesting the need for a consistent model validation framework.
- ADMS applications often utilize aggregated or lumped characteristics from the point of interconnection at the substation due to the lack of full circuit models.
- Utilizing behind the meter DER as an ADMS application, or integrated with DERMS is limited by the existing standards for integration including IEEE 1547. However, new standards released in 2017 (estimated) may allow greater use of these control capabilities and present a large opportunity for ADMS applications.

Some state-of-the-art examples of deployment of applications include:

- Outage location and restoration with smart meters at the Pacific Gas and Electric Company (PG&E).
- Forecasting integration for high penetration of DER at the Hawaiian Electric Companies (HECO).
- Enhanced communication and situational awareness through a fiber optic backbone at Chattanooga Public Utility.

3.3.5. Federal role

The federal role in this effort is, broadly, to envision and develop the applications and functions that will have market demand/energy system impact on time scales outside of short business development cycles. An integrated ADMS application suite would provide significant benefit to distribution system operation and build out; however, there is risk in developing these tools due

to the technical challenges—including the difficulty of operating each class of applications. Specific activities for the unique position of federal laboratory researchers to pursue include:

- Advancing and applying fundamental knowledge for optimal decision making in distribution networks.
- Applying National Lab advanced HIL testing expertise and capabilities to develop new and deeper understanding of ADMS applications.
- Developing and applying a common approach across lab testbeds for effective validation of emerging applications.
- Soliciting stakeholder feedback and guidance through technical advisory groups.

3.3.6. Technical activity descriptions

The technical tasks are organized into the following priority areas:

Non-emergency network operations:

- Develop and translate model identification and distribution state estimation functions that deliver cross-application information for network planning and operations decisions.
- Develop, and translate into cross-application functionality, distribution network modeling strategies that balance computational speed with approximation errors. (For example, linear models are solved efficiently but introduce errors; full nonlinear representations are accurate, but impractically slow in most optimization applications)
- Develop forecasting algorithms rooted in injection/extraction forecasts derived from SCADA, customer AMI, solar production data, and advanced sensors including PMUs for distribution systems. Investigate the tradeoff between locational network resolution and aggregated forecast accuracy.
- Develop optimization tools that support a range of applications depending on how they are configured (including coordinating power flow for transmission-level integration, DERMS for maximizing hosting capacity, peak demand management to defer capacitor bank and conductor upgrade projects, CVR, VVO, and phase balancing).
- Develop optimization tools that facilitate network-level decision-making under model uncertainty, forecast error, and faulty state estimates. This could include stochastic and robust optimization algorithms for power flow coordination and optimization.
- Develop decentralized “communications failure safe” algorithms that maximize network performance. These could be applications emerging in the near term such as droop-controlled power electronic inverter solutions or longer term solutions such as decentralized control algorithms.
- Develop framework and implement methods that facilitate local transactions among distributed resources as an alternative to command and control architectures.
- Develop strategies for tuning and sending DER control settings (that is, inverter voltage regulation and ride-through functions) and legacy voltage regulation equipment to support high penetration of renewable generation.
- Platform communications standardization: develop the minimum data requirements for all operations applications so as to allow for interoperable application design for ADMS environments.

Reliability and outage management:

- Develop and demonstrate—in both vendor specific and open platforms—control laws for automated and manual contingency switching plans based on off-line power flow

scenario calculations. Models and power flow solvers can be shared with those employed in the non-emergency operations module above.

- Develop “rules” (or control laws) for switching off line that can then be implemented in real time using only immediately available information. These rules could, for example, coordinate switching and restoration actions to maintain power quality and minimize customer interruptions. Off-line control laws can be determined using cross-application power flow solvers, models, and forecasts.
- Develop network connectivity and validation analysis modules that operate as “reduced form” model identification routines (see Network Operations activities above) and resolve network connectivity maps.
- Build next generation FLISR into an integrated ADMS application, introducing location of fault/prediction of event/automated reconfiguration and also utilization of DER controls in system restoration plan.
- Pursue predictive analytics—based on integrated sensor measurements, state estimates, and power flow solutions—to determine mean-time-to-failure of equipment, planned maintenance, and probability of outages.
- Platform communications standardization: develop the minimum data requirements for all reliability and outage management applications so as to allow for interoperable application design for ADMS environments.

Data analytics & communications:

- Integrate customer outage calls, complaints, and pictures with platform for full relational situational awareness.
- Sensor and communications traffic study, linked with grid modernization objectives, to determine both optimal placement and communication requirements for a suite of applications.
- Develop tools to support verification of customer generation and load performance.

3.3.7. Milestones

Near term (1-2 years)

- Application interoperability and communications standards review.
- Develop and implement network optimization methods that plan network operations under uncertainty.
- Develop tools to characterize system behavior from large sets of heterogeneous data sources. These efforts are to include historical and real-time analysis.
- Demonstrate that ADMS software can provide transmission support by delivering precise and certain control load bus states (power and voltage) with high precision and accuracy.
- Integration of sensors and data to ADMS applications interface.

Mid term (3-4 years)

- Integrate centralized and decentralized ADMS applications into existing DMS vendor platforms.
- Demonstrate a subset of ADMS functions in HIL testbeds.
- Extend network optimization methods beyond transmission support actions to capture host of other network management objectives including maximizing DER penetration.
- Enable visualization of feeder characterization from data analytics efforts.

- Translate power flow and state estimation tools to emergency network management applications.
- Integrate ADMS algorithms into commercial products.

Long term (5+ years)

- Develop commercial ADMS applications that demonstrably reduce ratepayer costs and improve reliability.
- Integrate load bus control into transmission system operator market and EMS applications.

3.4. ADMS Foundational: Advanced Control

3.4.1. Technical goal and objective

Increasing penetration of stochastic and variable renewable generation (both centralized and distributed) in transmission and distribution grids is decreasing the availability of traditional forms of generation used to control real power for balancing load and reactive power for regulating voltage magnitude. Viewed in this way, even the expansion of flexible natural gas generation in many parts of the U.S. may ultimately be limited in its ability to provide adequate controllable resources. These changes are driving an emerging transition to leverage a large latent capability in the grid by controlling DERs to supplement and replace the control of traditional generation.

The goal of this program element is to develop theoretical foundations for new control solutions for the U.S. power grid. The focus is on distribution systems to support ADMS program objectives for transitioning the power grid to a state where a large number of DERs are participating in grid control, to enable the grid to operate with lean reserve margins and to enable resilient distribution feeders with a high percentage of low carbon DERs.

In addition to its emphasis on distribution, this program element will also address integration of a large number of DERs into transmission and market operations (for example, automatic generation control [AGC], security constrained economic dispatch) using hierarchical control theory and solutions, including the coordination between bulk system controls and the new controls and optimization developed in this work. The large amount of R&D already performed on these transmission-level applications will be leveraged.

The major outcome of this technical area will be to develop novel control solutions that access the currently latent control capability in many DERs (generation, storage, and load), thereby creating a system that is more flexible than the legacy system while enabling the following:

- Control systems that are more effective at keeping operating conditions within prescribed safety margins.
- Contribution to a 33% decrease in cost of reserve margins while maintaining reliability by 2025.
- Enabling of the interconnection of intermittent power generation with less strict margins and with reduced need for electrical storage—contributing to a 50% decrease in the net integration costs of clean energy technologies by 2025.

3.4.2. Technical challenges

These expected and ongoing changes in the nature of the electrical power system are being hindered by the lack of effective controls to manage these new DERs. Where control solutions do exist, they are stressed or limited because they operate too slowly, do not provide the required control accuracy, do not enable the actuation and control of diverse sets of large numbers of new intelligent DERs, do not effectively manage the uncertainty of DER response on multiple time and grid scales, do not integrate these new DERs with existing system controls, and are not easily transferrable to multiple control settings.

Advanced control solutions that are able to achieve the ADMS vision need to have the following properties:

- Easy to integrate with legacy systems to enable the adoption of advanced solutions in a smooth manner.
- Able to simultaneously coordinate the response of a large number of DERs that must also be compatible with scalable communications, information, and computational architectures.
- Able to control diverse sets of DERs that have distinct actuation inputs, device parameters and responses (continuous versus discrete), for example, PV inverters, battery energy storage (including electric vehicles), thermostatically controlled loads, distributed generation, fuel cells, etc.
- Must match the availability, time resolution, spatial granularity, and uncertainty of the sensor data and actuation signals.
- Must manage voltage, power flow, and other network constraints while optimizing the spatiotemporally coordinated actuation of a large number of devices.
- Must be able to address the full range of timescales by providing actuation of the optimal resource at the current time while anticipating the effects on future flexibility.
- Must manage all sources of operational uncertainty, including intermittent distributed generation and the uncertainty of the response of a large number of DERs, to limit the risk to power systems at minimum cost.
- Should support market-based and non-market-based models for DER engagement in grid control and the integration with bulk power system markets.

3.4.3. Technical scope

Achieving the ADMS and Grid Modernization MYPP goals requires significant advancements beyond the current state of the technology and innovations in several interrelated areas: (1) Co-Development of Control Theory and System Architecture to create concrete directions of theoretical development, which will be measured against metrics also developed in this activity; (2) Theory for Hierarchical, Decentralized, Distributed, and Risk-Aware Controls that enable the design and analysis of control algorithms for at least 10,000 DERs embedded in distribution and transmission networks; and (3) At-Scale Testing via Simulation to validate the performance of the developed control solutions and foster development of transition plans for industry demonstrations.

Co-development of control theory and system architecture. To achieve transferable, resilient, and deployable control solutions, the expertise and experience of the industry partners (Oncor Electric Delivery, PJM Interconnection, United Technologies Research Center [UTRC]) will be leveraged to co-develop control approaches and theory along with control, communications, and information system architectures. Although informed by industry, co-development will ensure

these architectures are also informed by control theory and not simply predefined by what exists today. These architectures will be economically deployable, represent industry approaches, and demonstrate a continuous evolution from today's legacy systems to the ADMS future vision. The architectures will be designed to be resilient to impacts of natural or malicious events. This task will collaborate with GMLC Task 1.2.1 by instantiating several of the architectures from that project to develop controls and by performing early testing and evaluation of these architectures against a set of control system metrics also developed within this task.

By directly incorporating grid systems, information and communications systems, and markets and industry structure into a single architectural representation, the spatiotemporal availability and resolution of sensor data and actuation signals and their respective aggregation and disaggregation are known and clearly defined. This upfront architectural integration enables the development of control theory and associated algorithms that provide high performance on each of the proposed architectures. It also enables the evaluation of the performance of architecture as the information and actuation availability is compromised by a natural event or cyber-attacks. At the same time, the control theories will inform architecture in GMLC Task 1.2.1 so that useful structural changes that support advanced control can be suggested to other parts of the industry, thus easing the adoption of new controls.

Theory for hierarchical, decentralized, distributed, and risk-aware controls. To accommodate massive numbers of DERs, architectural options that emerge are expected to be hierarchical and distributed in nature. At the distribution network level, objectives include estimating the bounds of DER flexibility and controlling within those bounds to meet “external” demands (for example, a reference signal provided by the ISO Bulk Market) while respecting “internal” constraints (for example, voltage magnitude and power flow limits on the host distribution circuits and substations). The device-level control objectives drill deeper into the device physics to develop theory for aggregating large numbers of diverse DERs (generation, storage, and loads) into ensemble models that ensure computational tractability while systematically incorporating end-use dynamics and physical constraints. The ensemble models should provide predictions of the average response, the fluctuations and uncertainty about that average response, and predictions of the impacts of both effects on the power system via the physics of power flow. Both the device-level and distribution network-level control systems should integrate seamlessly with the ISO Bulk/Wholesale Market control systems as defined in the candidate architectures. The proposed control strategies are expected to be open, flexible and interoperable, exhibiting “plug-and-play” features, supporting dynamic system configuration, and respecting the existing mechanisms and engineering realities within each subsystem.

At-scale testing via simulation. The complexity and nature of the required testing is determined by many factors such as the size of the control network, location and type of constraints, time scale and time step, resource and load characteristics, aggregation of the loads and DERs, temporal and spatial diversity of the resources, and markets and regulations. Initial testing will include simplifications of these factors to prototype and improve the control implementations. These simplifications will be replaced with more realistic assumptions as the control designs reach a desired level of performance and move toward a more integrated, at-scale testing. Through simulation and modeling, the performance of the control designs will be assessed and iteratively improved to guarantee stability and reliability under a wide variety of test scenarios. The test methods, scenarios, and protocols will be developed in collaboration with the industry partners (Oncor, PJM, UTRC) to ensure relevance to their operating conditions and requirements. Via an industry workshop, the testing results will be shared and vetted with the industry partners and a wider set of industry stakeholders (utilities, regional reliability organizations, control system developers, and software vendors) to ensure they understand the test protocols and results and the availability of control solutions for future demonstration and transition to practice.

Modeling and analysis of advanced grid control applications require a fundamental understanding of the behavior of the physical systems and an integrated modeling approach that portrays the control system performance in the setting of the surrounding bulk generation, transmission infrastructure, market systems, reliability coordination, and other aspects of utility operations. The control systems developed in this project will be tested for stability and performance in unique numerical simulation environments. Development of the simulation environments, and the testing itself, will be an iterative process in close coordination with control theory developments and with the ADMS Platform and ADMS Testbed technical areas and GMLC project 1.4.15, Co-Simulation of Transmission, Distribution, and Communications (TDC).

3.4.4. Status of current development

The current state of the relevant control technology is perhaps best described by summarizing a few current DER control applications in use, and a few being studied theoretically, in the context of the desired control and optimization system properties described above.

Spinning reserve and critical peak management from demand response. These applications generally only tap into a relatively small number of large industrial and commercial loads. The control is typically open loop and not continuous. The time scales for actuation are slow (~10 minutes), and accuracy requirements are not strict. These relatively loose requirements have spawned mostly manually driven actuation that is not scalable, includes limited use of optimization, does not consider power flow effects, and includes little if any consideration of the uncertainty of the response.

Battery storage control. In many applications, battery storage provides a single “anchor” end use service,¹¹ for example, peak shaving at substation transformers to defer upgrade investments. Control algorithms are typically focused on this single anchor service without coordination at shorter or longer time scales to extract additional value. The control typically does not coordinate with other DERs on the distribution grid, and power flow and voltage effects are mostly ignored.

¹¹ [DOE/EPRI 2013] “DOE/EPRI 2013 Electricity Storage Handbook in Collaboration with NRECA,” Technical Report SAND2013-5131. Sandia National Laboratories, July 2013.

PV inverter control. Although smart inverters are not widely deployed, this area has seen very active theoretical research. Approaches have included policy-based open loop control¹² with off-line consideration of power flow, advanced distributed algorithms that integrate power flow approximations,^{13,14} centralized methods that integrate power flow relaxations,¹⁵ and methods that utilize continuous ODE representations of power flow.¹⁶ These methods have made good theoretical progress on the specific problem of using advanced inverters to control power flow and voltage along distribution circuits; however, they have not generally addressed broader control and optimization issues related to integrating these inverter controls with control of other DERs or the management of uncertainty from intermittent generation or the control system response.

Ensemble control of loads. Several efforts have addressed limited aspects of controlling large ensemble of loads, primarily thermostatically controlled loads (TCL). Approaches have included data-driven statistical models,¹⁷ statistical state estimation,¹⁸ and Fokker-Planck like models of physical TCL dynamics.^{19, 20} However, these efforts have not explicitly modeled or incorporated fluctuations of the ensemble load and the propagation of that uncertainty to higher levels of a hierarchical control system. Also, these approaches typically do not consider the physics of power flow and the effect of ensemble control on the voltages at the loads being controlled.

3.4.5. Federal role

Establishing a novel overall control solution for the U.S. power grid is a task that is much beyond any single private stakeholder or research organization and requires coordination across teams and disciplines beyond the scope of typical university-led research efforts. It calls for collaboration by several national laboratories that jointly have the required capabilities and individual credibility in their areas of expertise in cooperation with several key industry partners.

¹² [Turitsyn 2011] K. Turitsyn, P. Sulc, S. Backhaus, and M. Chertkov. "Options for Control of Reactive Power by Distributed Photovoltaic Generators." *Proceedings of the IEEE*, 99(6):1063–1073, June 2011.

¹³ [Sulc 2014] Sulc, P.; Backhaus, S.; Chertkov, M. "Optimal Distributed Control of Reactive Power via the Alternating Direction Method of Multipliers." In *Energy Conversion*, IEEE Transactions, vol. 29, no.4, pp.968-977, Dec. 2014.

¹⁴ [DallAnese 2014] DallAnese, E.; Dhople, S.V.; Johnson, B.B.; Giannakis, G.B. "Decentralized Optimal Dispatch of Photovoltaic Inverters in Residential Distribution Systems." In *Energy Conversion*, IEEE Transactions, vol. 29, no. 4, pp. 957-967, Dec. 2014.

¹⁵ [Lingwen 2015] Lingwen Gan; Na Li; Topcu, U.; Low, S.H. "Exact Convex Relaxation of Optimal Power Flow in Radial Networks." In *Automatic Control*, IEEE Transactions, vol. 60, no. 1, pp. 72-87, Jan. 2015.

¹⁶ [Wang 2012] Danhua Wang; Turitsyn, K.; Chertkov, M., "DistFlow ODE: Modeling, analyzing and controlling long distribution feeder." In *Decision and Control (CDC)*, 2012 IEEE 51st Annual Conference, pp. 5613-5618, 10-13 Dec. 2012.

¹⁷ [Callaway 2009] Duncan S. Callaway. "Tapping the energy storage potential in electric loads to deliver load following and regulation, with application to wind energy," *Energy Conversion and Management*, Vol. 50, Issue 5, May 2009.

¹⁸ [Mathieu 2013] Mathieu, J.L.; Koch, S.; Callaway, D.S. "State Estimation and Control of Electric Loads to Manage Real-Time Energy Imbalance." In *Power Systems*, IEEE Transactions, vol. 28, no. 1, pp. 430-440, Feb. 2013.

¹⁹ [Kundu 2011] S. Kundu, N. Sinitsyn, S. Backhaus, and I. Hiskens. "Modeling and control of thermostatically controlled loads." In *Power System Computation Conference (PSCC)*, 2011. Stockholm, Sweden.

²⁰ [Sinitsyn 2013] Nikolai A. Sinitsyn, Soumya Kundu, Scott Backhaus. "Safe protocols for generating power pulses with heterogeneous populations of thermostatically controlled loads." *Energy Conversion and Management*, vol. 67, March 2013, pp. 297-308.

An effort with this breadth in expertise and supported by the U.S. government will have the required credibility to convince individual stakeholders to engage in its deployment.

3.4.6. Technical activity descriptions

The three main areas of technical activity are: (1) Architecture and Metrics; (2) Modeling and Controls; and (3) Testing and Validation. Each of these activities is described in detail next.

Task 1: Architecture and Metrics. In this task, several options will be formulated for adaptive and agile architectures. These architectures will focus on structure of the control systems in conjunction with other related grid structures, namely electric infrastructure, industry structure (including markets), information and communication technology (ICT) superstructure (including communication networks for sensing and control), and overall coordination framework. The control architecture options will set the structural bounds within which optimization can be performed for stability and efficiencies of control operation in an all-hazards environment spanning T&D including the physical power system, communications networks, data aggregation, and control signal disaggregation. The architecture task will deliver relevant emerging trends and systemic issues lists (part of requirements), reference models (problem domain depictions) for control, models for market/control interactions in high DER distribution systems, and multi-structure architectures for control, communications, and data management in joint T&D environments.

A set of metrics for relevant control methodologies (reliability, resiliency, scalability, clean, affordability, security, etc.) will also be developed. A scalable approach will be presented that is applicable to system integrity and extensible to the business case for the performance through comparison with a modeled physical system. Instead of focusing on individual contributors of performance separately, a unifying methodology will consider impact to the resultant environment and the individual, controlled feature of this environment.

Finally, the performance of each developed control methodology in Task 2 will be assessed using the developed metrics. Technical performance metrics will be evaluated using simulation, for example, using convex relaxation theory to calculate bounds on the control performance. Non-technical metrics will be evaluated using methods developed in GMLC Project 1.1.

Task 2: Modeling and Controls. In this task, models for a range of individual and aggregations of large numbers of continuous and discrete-control DERs will be developed. A primary focus is thermostatically controlled loads and inverter-based DER (for example, photovoltaic systems and battery storage). Other loads and DERs will be considered, but these two general categories of devices define a wide swath of the flexible loads and DERs. The models developed will depend on the architectural options from Task 1. However, two main directions are expected—device-level models and ensemble-level models. Devices may be modeled via switched stochastic differential equations, with the stochastic terms representing exogenous fluctuations as well as uncertainty in the transitions between the states. This model will be explored analytically and numerically. Aggregations of these devices will be modeled using methods from statistical physics that describe the probability distributions of loads that are in the on/off state. A computational scheme will be developed to describe the spectral properties of the aggregate system as well as cross validate analytical and computational results.

This task will also explore power flow relaxations and approximations that are informed by the architectural options in Task 1 and the load/DER models developed in Task 2. The exploration will take two complementary paths. The first path will catalog the wide variety of power flow relaxations and approximations that have been developed recently with different levels of fidelity and computational tractability. The computational requirements and control architecture choices must drive selection of appropriate power flow models for different applications in the control theory (for example, real-time applications must have very tractable models that may come at the expense of fidelity). To balance these trade-offs, the first goal of this task is to catalog existing power flow relaxations and approximations, identify how their strengths and shortcomings align with the needs of the control theory and architecture choices, create a roadmap describing a plan to make them practically useful in context of other control theory efforts, and improve quality of relaxations and approximations. The second path will develop new, non-traditional methods that utilize concepts of monotonicity applied to radial distribution circuits to compute regions of voltage feasibility in the space of load/DER actuation.

This task will further focus on topologies for organizing controls related to DERs and algorithms for deploying the controls. A distributed control theoretic framework for handling large numbers of DERs will be developed. As part of this, aggregate models of load/DER (as developed in the tasks described above) will be incorporated. This task will investigate how to fit the developed control solutions into an integrated electricity system that includes integrated T&D systems and wholesale and retail markets (real-time and day-ahead). The communication requirements needed to realize the integrated system will also be considered. As a more substantial integration of DERs will also affect wholesale markets, the developed approach will take the dynamic coupling introduced into account. Furthermore, to support emerging DSO models, this task will provide a theoretical control framework for supporting a potential two-market system, where DERs will have different value in different markets and on different time-scales. In particular, the framework will target integrating ancillary and real-time energy services to ensure DERs are exploited to full potential.

Task 3: Testing and Validation. The initial focus of this task is targeted at specifying and developing a numerical simulation test bed in collaboration with the ADMS Platform, ADMS Testbed technical areas, and GMLC project 1.4.15, Co-Simulation of Transmission, Distribution, and Communications. The test bed will be designed specifically to allow testing of various control approaches. The control methods will then be tested on the numerical simulation test bed under a range of load, generation, grid, and communications conditions expected in normal grid operations and during severe operational upsets such as faults, transmission contingencies, and other compromises. Further, transition plans for industry demonstration projects will be developed for the most promising control methods.

3.4.7. Milestones

Project Years 1-3. The milestones for the first three years of the project have been developed in close collaboration with the DOE and GMLC, and are listed in the table that follows:

| Description | End Date | Type |
|---|-----------------|--------------------|
| TASK 1 | | |
| Document architectural reference models for control that include three key scenarios: legacy systems, communications-heavy systems, and communications-light systems. | 10/1/16 Y1Q2 | Annual |
| Document architectural reference models with extensions to include market/control interactions, multi-structure architecture diagrams, and detailed data. | 4/1/17 Y1Q4 | Midterm |
| Complete evaluation of architecture for scalability and cost, providing guidance on granularity of deployment and distribution of control systems. | 10/1/17 Y2Q2 | Annual |
| Complete evaluation of architecture for security and resilience, providing guidance on key architectural nodes that require specific cyber and/or physical protection. | 4/1/18 Y2Q4 | Midterm |
| Complete evaluation of test bed data for control system computational scalability and resilience. | 4/1/19 Y3Q4 | End/End of Project |
| TASK 2 | | |
| Document catalog of required individual and aggregate load/DER models and roadmap of theoretical development steps to achieve tractable load/DER models. | 10/1/16 Y1Q2 | Annual |
| Document catalog of existing and alternative power flow relaxations and approximations for distribution systems with discussion of applicability to optimization and control of distribution networks, and down select for further numerical testing. | 10/1/16 Y1Q2 | Annual |
| Document preliminary formulation and development roadmap for risk-aware control of multiple distribution circuits with >10,000 DER including power flow physics, legacy equipment, and network constraints. | 10/1/16 Y1Q2 | Annual |
| Document initial design of control methodologies for aggregated and individual load/DER models. | 10/1/16 Y1Q2 | Annual |
| Document analytical solutions for static (unactuated) load/DER models. | 4/1/17 Y1Q4 | Midterm |
| Document final specifications for the hierarchical control framework for each of the architectural reference models including topologies, communications, data exchange, and time scales. | 4/1/17 Y1Q4 | Midterm |

| | | |
|---|------------------|--------------------|
| Document preliminary analytical solutions for dynamic (actuated) load/DER models. | 10/1/17 Y2Q2 | Annual |
| Complete and document assessment of existing power flow relaxations and approximations for distribution systems with comparisons of errors and computational performance. | 10/1/17 Y2Q2 | Annual |
| Risk-aware control/optimization of ~10 distribution feeders including stochastic (uncontrolled) DER, legacy/utility equipment, and power flow physics. | 10/1/17 Y2Q2 | Annual |
| Document preliminary theoretical framework for wholesale retail market integration. | 10/1/17 Y2Q2 | Annual |
| Document analytical solutions for dynamic (actuated) load/DER with numerical simulation validation. | 4/1/18 Y2Q4 | Midterm |
| Fully develop and document power flow relaxation and approximation approaches including recommendations for integration into control/optimization methodologies. | 4/1/18 Y2Q4 | Midterm |
| Document final theoretical framework for wholesale retail market integration. | 4/1/18 Y2Q4 | Midterm |
| Risk-aware control/optimization of ~10 distribution feeders including ~10,000 controlled DER, legacy/utility equipment, and power flow physics. | 10/1/18 Y2Q2 | End of Project |
| Addition of co-optimization of energy and ancillary services to risk-aware control/optimization of ~10 distribution feeders including ~10,000 controlled DER, legacy/utility equipment, and power flow physics. | 4/1/19 Y3Q4 | End/End of Project |
| Document final theoretical framework for co-optimization of energy and ancillary services. | 4/1/19 Y3Q4 | End/End of Project |
| TASK 3 | | |
| Document numerical simulation test bed requirements and down select (adapt existing versus develop new). | 10/1/17 Y2Q2 | Annual |
| Document control system testing plan and implementation plan for test bed development/adaptation. | 4/1/18 Y2Q4 | Midterm |
| Test bed implementation complete, and testing initiated. | 10/1/18 Y3/Q2 | End of Project |
| Numerical simulation testing of control system computational scalability and resilience complete. | 4/1/19 Y3Q4 | End/End of Project |

Project Years 4-5—These project years have not been part of the detailed planning; however, additional work beyond the end of project year 3 will enable achieving several additional goals and related milestones. These high-level milestones include:

- Y4/Q2: More detailed integration of the controls developed in project years 1-3 with bulk electric system markets to include the effects of stochasticity and control response uncertainty on the commitment and dispatch of large central generation.
- Y4/Q4: Deeper integration of the controls developed in project years 1-3 with distribution-level markets accounting for the quality of control service achieved by different DERs within the network.
- Y5/Q4: Development of control system algorithms for distributed, peer-to-peer communications systems that manage DER and utility control equipment with much reduced burden on utility supervisory control systems and communications networks.

3.5. ADMS Integration with EMS and BEMS

This section describes the activity of integrating ADMS into the next generation grid operating system under a new system control paradigm. Within this activity, RD&D will be performed to develop and demonstrate advanced grid control technologies that will allow the system to be operated with less reserve margin, dramatically enhancing the efficiency of the overall system. To enable this vision, it will be necessary to achieve greater end-to-end integration across all levels of the supply and delivery infrastructure. This activity will accomplish greater integration between ADMS, grid-level EMS, and BMS. Linking these systems will enable seamless optimization and control across the entire power system. Open standards and middleware software approaches will be critical to the success of this objective.

3.5.1. Technical goal and objectives

The current approach to electric power system operations and controls was developed over the last three to four decades using a piecemeal approach, within narrow functional silos for DMS and EMS software tools that offer minimal ability to coordinate or interact. Additionally, end-use tools such as BMS, DERMS, and MC are totally independent from grid control software systems. The rapid growth of renewable power generation, the increased use of electric vehicles, and the increased need to integrate customers with the power system are rendering the current generation of grid operating systems obsolete.

The goal of this activity is to create an integrated grid management framework that will be akin to having an autopilot system for the grid's interconnected components—from central and distributed energy resources at bulk power systems and distribution systems, to local control systems for energy networks, including BMS. By the end of five years, this activity will successfully:

- Develop an open framework to coordinate EMS, DMS, and BMS operations, and then demonstrate the new framework on a use case at GMLC national lab facilities. The test

system will have more than 15,000 transmission substations and will involve high penetration of DERs or microgrids (more than 50 percent).

- Deploy and demonstrate new operations applications—probabilistic risk-based operations, forecasting data integration and decision support, and heterogeneous sensor data integration—that transform or extend existing EMS and DMS applications.
- Demonstrate the value of integrating ADMS into this new generation grid operating system.

3.5.2. Technical challenges

Current grid operations and control systems have relied on decoupled approaches to transmission, distribution, and local energy networks. This approach is not capable of fully addressing the holistic approach offered by complex smart grid systems, where monitoring effects of renewables and electric energy storage in the distribution network and for end users has a significant impact throughout the entire network. The future grid operations and control systems must be able to monitor, protect, and automatically optimize the operation of the grid's interconnected elements—from the central and distributed generator through the high-voltage network and distribution system, to building automation systems, to controllers for DERs and microgrids, and to end-use consumers, including their thermostats, electric vehicles, appliances, and other household devices.

Additionally, future electrical grids will be characterized by higher levels of stochastic generation, by larger load fluctuations that impact system controls, and by operating closer to grid limits. Continued use of deterministic methods and algorithms that do not account for the stochastic nature of renewable and/or distributed generation, or load fluctuations, will effectively blind electric system operators to the increased risk caused by those fluctuations. As a result, transmission and generation limits will be exceeded, and voltage and transient stability boundaries will be violated.

Grid operations presently handle large amounts of multi-source and multi-scale data from disparate sources, such as the SCADA system, asset management system, OMS, weather data system, and GIS system. National grid modernization efforts to facilitate adoption of smart grid practices in recent years have increased adoption of smart grid technologies, such as PMUs, AMI, and smart metering. These deployments are expected to generate a tsunami of additional data. This large influx of data offers multiple advantages; however, without proper structure and analysis, it can overwhelm the systems, causing chaos in data acquisition, data storage, and data analysis.

3.5.3. Technical scope

This activity will develop an open framework to exchange information between ADMS, electric grid's EMS, and BMS control systems. To create this framework, interfaces to ADMS, EMS, and BMS that are suited for the hierarchical structure of organizations' utilities, as shown in Figure 7, will be built. The interfaces will align with GMLC 1.2.1 (grid architecture development) and follow the guidelines developed in that project. The diverse and large number of buildings connected to the advanced distribution system requires a framework that enables scalable messaging, which will be installed at several locations and registered with each location. In addition, the integration

requires building profiles for the information models and data exchange. The activity will use interoperability standards that are developed from GMLC 1.2.2 (interoperability) and common information models (where available) to ensure a common interpretation of the data exchanged across the interface.

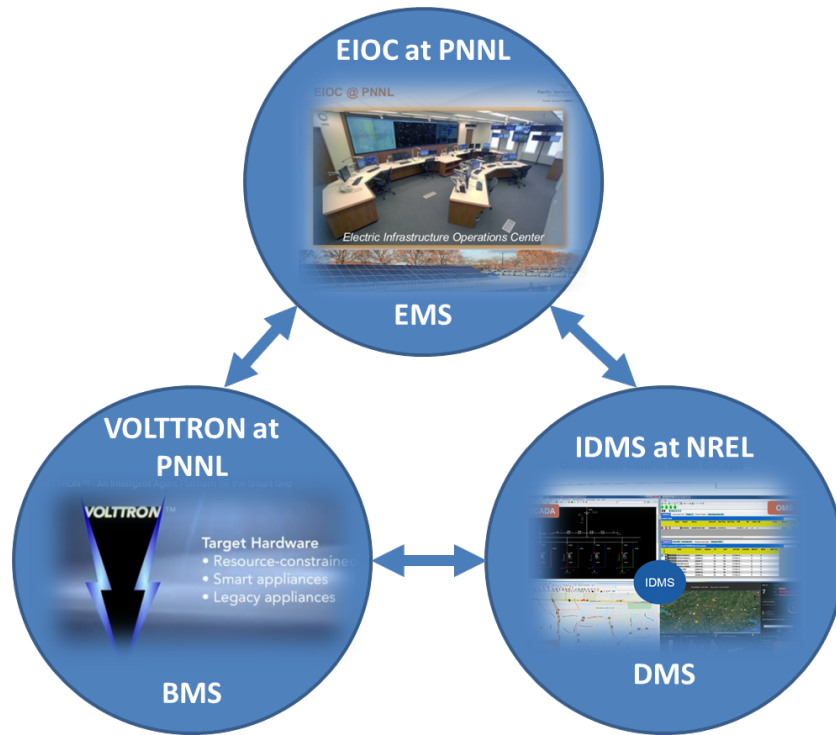


Figure 7. Collaborative effort to develop a Multi-Scale Integration of Control System

To achieve the end-to-end control system coordination, this activity will also develop applications that quantify and incorporate uncertainty and also integrate with sensor data to provide decision support for control room applications. This activity will investigate methods and develop software tools that utilize data from sensor networks at different spatial and temporal scales, forecasting applications for monitoring grid health, detecting incipient failures or faults and locating their source, managing the response to a grid event, and developing strategies for mitigating future events. Some machine learning tools developed through the concept paper “Multi Scale Data Analytics” will be leveraged on this activity. Probabilistic methods and algorithms will also be developed to incorporate the effects of stochastic fluctuations. With a move to probabilistic models, decisions regarding risk levels become an explicit decision rather than an implicit assumption. Risk metrics will also be developed to estimate the probabilities of violations of system security; compute commitment, dispatch, and control actions to constrain these probabilities within acceptable limits; and yield defensible prices for these actions and for injections that increase systems risks.

3.5.4. Status of current development

This section identifies the current development and capabilities of the national lab complex that are relevant to the integration of ADMS, EMS, and BMS.

- **EIOC at PNNL:** The EIOC is used by researchers to explore how changes in the way the nation's electrical grid is operated can improve the grid's reliability, lower costs, and lessen environmental impacts. The EIOC's focus is on developing real-time tools and supporting their integration into operating systems. Thus, the EIOC supports the nation's need to develop new tools that provide not only a better view of the current power grid, but also faster and more accurate predictions of what might be happening so operators can quickly respond. The EIOC allows researchers to work with real data—running scenarios to determine how to increase capacity and improve reliability models, and testing new technology without the cost and risk of disrupting the system. Because the EIOC is a safe setting, researchers can work through the iterative process of developing and refining technology more quickly. The EIOC has been used for several user studies evaluating next generation operation tools, including a ramping uncertainty tool, an improved graphical presentation of contingency analysis data, and a shared perspective tool to enhance shared understanding between control centers.
- **VOLTTRON at PNNL:** VOLTTRON is an open-source platform for secure distributed sensing and control integrating devices with applications for controlling those devices that were developed by PNNL. VOLTTRON can be used as the basis for a BMS by developing a set of services to provide this functionality. For example, Virginia Tech has built BeMOSS (<http://www.bemoss.org/>), an application on top of VOLTTRON, which acts as a BMS for small residential buildings. Other examples of services implemented to achieve this functionality include automated discovery of certain devices on a network, a common data format for all devices and agents, and a user interface for controlling the deployment.
- **Integrated Distribution Management System (IDMS) at NREL:** NREL collaborated with Duke Energy and Alstom Grid to implement comprehensive modeling, analysis, visualization, and hardware that is representative of Duke Energy's utility feeder at the NREL ESIF. This project helped Duke Energy understand the impact of smart inverters by implementing them in GIS, DMS, and SCADA. The Alstom Grid IDMS was implemented in ESIF systems.
- **PHIL Platform with remote distribution circuit co-simulation between PNNL and NREL:** NREL built the capability of integrating PHIL with a large distribution simulation and successfully demonstrated remote co-simulation with PNNL. In the demonstration, the advanced PV inverters are tested at power using NREL's PV and grid simulators interacting with GridLAB-D distribution feeder software models at PNNL. This geographical flexibility allows researchers to interconnect hardware and/or software across multiple sites to leverage unique equipment, devices, measurements, or other capabilities.
- **Integrated Transmission, Distribution, and Communication Modeling and Simulation at Lawrence Livermore National Laboratory (LLNL):** LLNL has developed the ParGrid simulator for coupled transmission, distribution, and communication analysis. ParGrid integrates LLNL's GridDyn transmission simulator; PNNL's GridLAB-D distribution simulator; and NS-3, an open-source communication network simulator. ParGrid was designed to federate multiple parallel simulators running across high performance computing nodes for large-scale power grid analysis. These distributed simulators communicate through asynchronous messages while maintaining a global time across all simulator components. This approach ensures efficient and correct execution. ParGrid

has the potential to conduct cross-domain analysis for a large-scale grid like California, which includes 6,000 transmission substations connecting about 10,000 distribution feeders to serve 15 million customers.

- **Stochastic optimization research at Sandia National Laboratories (SNL) and Los Alamos National Laboratory (LANL):** SNL developed solvers for stochastic unit commitment (UC) to achieve tractable solution times when solving realistic ISO-scale problems. The solution method uses a decomposition technique known as “progressive hedging” and was demonstrated using a problem similar to the size of ISO New England (for example, approximately 350 generators) with hundreds of scenarios representing the stochastic nature of load and wind at very high penetration levels. Solution times were reduced from intractable to tens of minutes using commodity clusters. This work was funded as part of ARPA-E’s Green Electricity Network Integration (GENI) portfolio of projects. The demonstrated cost savings associated with deployment of stochastic UC in systems with high penetration of renewables were 3-4% of the total production costs, while increasing the reliability of the system. SNL also designed stochastic process models that use historical load, wind, and solar forecast power generation data with corresponding actuals to produce well calibrated probabilistic forecasts in the form of probability weighted scenarios for those three sources of uncertainty. Under the DOE/OE Advanced Grid Modeling (AGM) Program, LANL developed probabilistic risks aware ED, called the “Chance-constrained Optimal Power Flow,” that allows for controlling the probability of violation of safety limits within an optimization problem. A scalable algorithm for solving the problem was developed exploiting methods from convex optimization, and the efficiency/performance of the algorithm was demonstrated on the Bonneville Power Administration (BPA) test case using very limited computational resources.
- **Dynamic Line Rating (DLR) at ANL:** ANL has investigated risk assessment and control of congestion management using real-time DLRs. Instead of examining the overloading risk caused by wrong forecasting on a single line, as done typically, ANL expanded the study to evaluate the probability of overloading on multiple lines to address a system-wide congestion problem. To this end, ANL developed a new distributionally robust optimization-based congestion management model that selectively uses DLR to alleviate system congestion while keeping the overload risk at the system level within a safe range. As the formulated model is computationally challenging to solve, ANL exploited the structure of the problem and utilized the latest development in stochastic programming to convert the original nonlinear problem to a readily solvable mixed-integer linear programming (MILP) problem. The computational results show that ANL’s proposed method can effectively utilize the value of DLR while keeping the simultaneous overloading risk under control.

3.5.5. Federal role

The technical risk of conducting multi-scale control system integration is high since it requires comprehensive technical expertise from transmission operations, to distribution operations, to various local energy network operating systems. Thus, the investment by the DOE is necessary, as this activity leverages the broad capability of experienced DOE and national lab personnel who can execute this work without further training. The budget required to perform multi-scale control system integration is large, and without DOE funding, the level of work to be completed is too extensive for the private sector to cover. The DOE can support the U.S. power industry with

this development, which uses the existing investment in national lab resources, built over time. Utilizing existing DOE facilities deployed at national labs (such as EIOC at PNNL and IDMS at NREL) will benefit the U.S. power industry as it continues to integrate advanced technology.

3.5.6. Technical activity descriptions

Task 1: Use case development. Develop a use case on which EMS, DMS, and BMS operate interactively for a test system that has more than 15,000 transmission substations and involves high penetration of DERs or microgrids (more than 50 percent); identify and select the prototype EMS, DMS, and BMS systems available at national labs or collaborative entities that will be used for Task 3.

Time Frame: 1-2 Years

Task 2: Open framework development for EMS/DMS/BMS integration. Develop open framework approaches for this use case to coordinate EMS, DMS, and BMS operations among themselves and with other local energy network controllers, such as microgrid controllers. The integrated platform will be demonstrated on the use case developed in Task 1. This will require extensive external stakeholder engagement and coordination with GMLC 1.2.1 (grid architecture) and 1.2.2 (interoperability).

Time Frame: 3-5 Years

Task 3: New application development on probabilistic risk-based operations for EMS. Investigate and incorporate probabilistic risk-based approaches into next generation EMS/DMS/BMS, shifting from a traditional contingency analysis model to a stochastic model. It is anticipated the risk-based distributed control system will reduce mitigation costs and minimize security violation risks typically found in deterministic approaches in large-scale use cases.

Time Frame: 3-5 Years

Task 4: New application development on uncertainty modeling and forecasting method for EMS. Develop applications that quantify and incorporate uncertainty and integrate with sensor and forecasting data to provide decision support for advanced control room applications. Examples include making better operational decisions with real-time information (such as DLR, dynamic reserve allocation, or real-time assessment of stability limits) and more precisely managing risk associated with potential future conditions (such as probabilistic forecasting and faults on systems that provide confidence information).

Time Frame: 3-5 Years

Task 5: New application development on heterogeneous sensor data integration for ADMS. Develop and demonstrate a tool for acquiring heterogeneous sensor data and populating an extended grid state that is informed by continual rediscovery of grid topology.

Time Frame: 3-5 Years

Task 6: Cost/benefit analysis of integrating ADMS into this new generation grid operating system. Define key assumptions for the ADMS—system/market conditions, DER adoption scenarios, and new ADMS applications (not used in the existing DMS)—and then conduct the cost-benefit analysis to monetize the impacts and add them to the accumulated costs to produce summary cost-benefit metrics. In addition to consolidating results, the economic analysis will trace how costs and benefits arise among various entities, including customers and society.

Time Frame: 2-3 Years

3.5.7. Milestones

| Milestone Name/Description | End Date | Type |
|--|------------|------------------|
| <ul style="list-style-type: none">• Complete report documenting use case and its data set.• Complete report documenting data exchange requirements and protocols.• Complete integration of LANL ED with SNL UC engine.• Complete report documenting investigation of DLR use. | 09/30/2016 | Annual Milestone |
| <ul style="list-style-type: none">• Demonstrate integration of EMS and DMS information in use case.• Complete initial data integration platform at NREL's ESIF with feeder data. | 09/30/2017 | Annual Milestone |
| <ul style="list-style-type: none">• Successfully demonstrate integrated EMS/DMS/BMS platform at a laboratory scale system. | 09/30/2018 | Annual Milestone |
| <ul style="list-style-type: none">• Successfully demonstrate integrated EMS/DMS/BMS platform at industry scale system. | 09/30/2019 | Annual Milestone |
| <ul style="list-style-type: none">• Successfully demonstrate the value of integrating ADMS into EMS/DMS/BMS platform. | 09/30/2020 | Annual Milestone |

4. Program Management and Stakeholder Engagement

4.1 Program Portfolio Management Approach

The ADMS Program follows a multi-step planning and management process designed to ensure that all funded technical R&D projects are chosen based on qualifications in meeting clearly defined criteria. This process entails the following:

- Competitive solicitations for financial assistance awards to industry, universities, and national labs on RD&D activities.
- Peer reviews of proposals in meeting the solicitation goals, objectives, and performance requirements.
- Peer reviews of in-progress projects on the scientific merit, the likelihood of technical and market success, the actual or anticipated results, and the cost effectiveness of research management. The ADMS Program and its in-progress R&D projects will be reviewed through this external review process once every two years, with evaluation results feeding back to program planning and portfolio management. The inaugural program peer review meeting is planned for 2017.
- Stage gate reviews to determine readiness of a technology or activity to advance to its next phase of development, pursue alternative paths, or be terminated. These readiness reviews will be conducted on an as-needed schedule based on project progression in meeting the established stage gate criteria.

- OE internal review of the ADMS Program annually to ensure continuous improvements and proper alignment with R&D priorities and industry needs.

The merit of R&D projects, individually and collectively, in achieving the ADMS Program goal targets will be made transparent by applying this management process consistently throughout the Program. Moreover, this merit, to be supported by rigorous analysis and evaluation, will be transparent in Program communications to the industry, the public, and other ADMS stakeholder organizations.

This MYPP will be used to guide ongoing projects and development of the ADMS Program portfolio of projects through 2020. It is anticipated that annual updates of the MYPP will be necessary to reflect current state of advances, priority needs, and resources availability. Implementation schedules for the activities and tasks described in the MYPP will depend on annual appropriations of the Program budget.

4.2 Stakeholder Engagement

Key industry stakeholder groups for the ADMS Program include electric utilities that employ ADMS and vendors that offer ADMS products to utility customers. The Program will engage these key stakeholder groups, and their associated organizations such as the American Public Power Association (APPA), Edison Electric Institute (EEL), National Rural Electric Cooperative Association (NRECA), and EPRI, to jointly plan and implement its research, development, and demonstration efforts. This engagement will be through the IAB set up for each of the Program's technical areas and through meetings/workshops with expanded participation of stakeholder organizations. Each IAB will be represented by experts and thought leaders from utilities and vendors in the respective program technical areas. IAB activities include annual meetings where the IAB reviews and evaluates the progress of projects in a technical area, along with quarterly web meetings to provide timely input to the projects. At the Program level, the ADMS Steering Committee (see Section 1.5) will guide the overall Program directions, portfolio development, and stakeholder engagement strategies.

The ADMS Program will also plan to hold meetings and/or workshops to seek input from and communicate results to much broader representations of stakeholder group organizations when warranted. Examples of such meetings and workshops include the biennial program peer review meeting, the industry stakeholder workshop for input to finalize this MYPP, and others to deep-dive on specific topics of great impact.

Having an effective stakeholder engagement strategy and practice is critical to reaching the Program targets of 20%, 50%, and 100% of vendors having ADMS capabilities in 2020, 2025, and 2030, respectively. The Program will continue to refine the strategy to broaden engagement of stakeholder group organizations necessary for the success of the ADMP Program.